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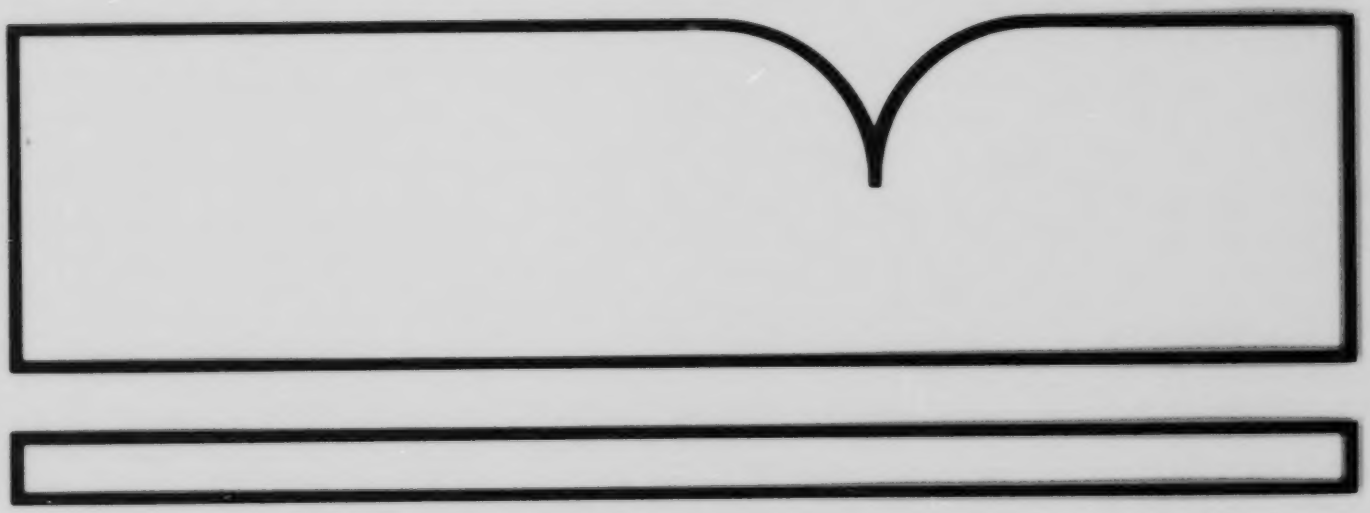
Description of the Industrial Combustion Emissions Model (Version 6.0)

Energy and Environmental Analysis, Inc.
Arlington, VA

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

May 88



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16. ABSTRACT The report describes the model methodology, key assumptions, data sources, and user options for Version 6 of the Industrial Combustion Emissions (ICE) Model, one of a number of National Acid Precipitation Assessment Program emission forecasting models. Future ICE Model runs may include model modifications recommended by EPA. The ICE Model projects air pollution emissions (sulfur dioxide, sulfates, and nitrogen oxides), costs, and fuel mix for industrial fossil-fuel-fired (natural gas, distillate and residual fuel oil, and coal) boilers by state and year (1985, 1990, 1995, 2000, 2010, 2020, and 2030).

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by

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ABSTRACT

The Industrial Combustion Emissions (ICE) Model is one of four stationary source emission and control cost forecasting models developed by the Air and Energy Engineering Research Laboratory for the National Acid Precipitation Assessment Program. The ICE Model projects air pollution emissions (sulfur dioxide, sulfates, nitrogen oxides and particulate matter), costs and fuel mix for industrial fossil fuel-fired (natural gas, distillate and residual fuel oil and coal) boilers by State and year (1980 baseline, 1985, 1990, 1995, 2000, 2010, 2020, and 2030).

This document describes the model methodology, key assumptions, data sources and user options for Version 6.0 of the ICE Model. Future ICE Model runs may include additional model modifications recommended by EPA.

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SECTION 1

INTRODUCTION

PURPOSE AND SCOPE OF MODEL

The Industrial Combustion Emissions (ICE) Model is a highly disaggregated and detailed process engineering model covering the consumption of fossil fuels (coal, distillate fuel oil, residual fuel oil, and natural gas) in industrial boilers. The ICE Model was developed by Energy and Environmental Analysis, Inc. (EEA) for EPA's Air and Energy Engineering Research Laboratory. It was developed to help decision makers assess a wide range of energy, environmental, and cost impacts resulting from policy alternatives. The ICE Model is currently being used by the Interagency Task Force on Acid Precipitation to project the impacts of alternative acid deposition control strategies.

The basic approach in the ICE Model is to project the characteristics of the industrial boiler population and to make a fuel choice decision for each group of boilers. The major industrial boiler characteristics include:

- New or existing unit
- Size (MW, MMBtu/hr heat input)
- Average annual capacity utilization rate*
- Local and Federal sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxide (NO_x) emissions standards.

Key input assumptions include:

- Base year (currently 1980) boiler population characteristics
- Projected fuel prices and total industrial boiler fossil fuel demand
- Boiler and pollution control equipment cost estimates
- Local and Federal air emissions regulations.

Major model outputs include:

- Projected emissions of SO_2, sulfates, NO_x, and PM
- Projected industrial boiler fossil fuel demand by fuel type (coal, distillate fuel oil, residual fuel oil, and natural gas)

---

* Expected annual fuel consumption/(design firing rate times 8,760 hours per year).

- Projected total capital and annual operating, maintenance, and fuel expenses.

Model outputs are available by State (excluding Alaska and Hawaii) and year (1980 baseline, 1985, 1990, 1995, 2000, 2010, 2020, and 2030).

Inputs to the ICE Model are determined from an analysis of macroeconomic factors. Figure 1 shows the interactions among these other factors which are outside the scope of the current ICE Model structure. The figure shows the relationships between:

- Overall economic trends
- U.S. energy markets
- Industrial energy demand
- Current ICE Model scope.

Analysis of overall economic activity identifies critical trends in "macroeconomic" variables. Several macroeconomic models have been developed which forecast growth in the aggregate demand and supply for final goods. Major model outputs include Gross National Product (GNP), private sector investment, government spending, production, personal consumption expenditures, and other economic parameters. These models generate forecasts of industrial activity (i.e., projections of the Federal Reserve Board Industrial Production Indices or value added data) by type of industrial group that affect the level of demand for energy services in the industrial sector. Other macroeconomic variables are used to forecast energy demand in other sectors (i.e., disposable income for the residential and commercial sectors).

The macroeconomic models thus provide key economic "drivers" of energy demand, such as industrial production growth. These "drivers" then serve as key inputs into a model of the U.S. energy markets to determine energy demand in the energy-using sectors of the economy. The "Energy Markets" essentially involve the interplay of demand and supply for alternative sources of energy (e.g., oil, coal), resulting in the determination of the price and level of use of various energy forms.

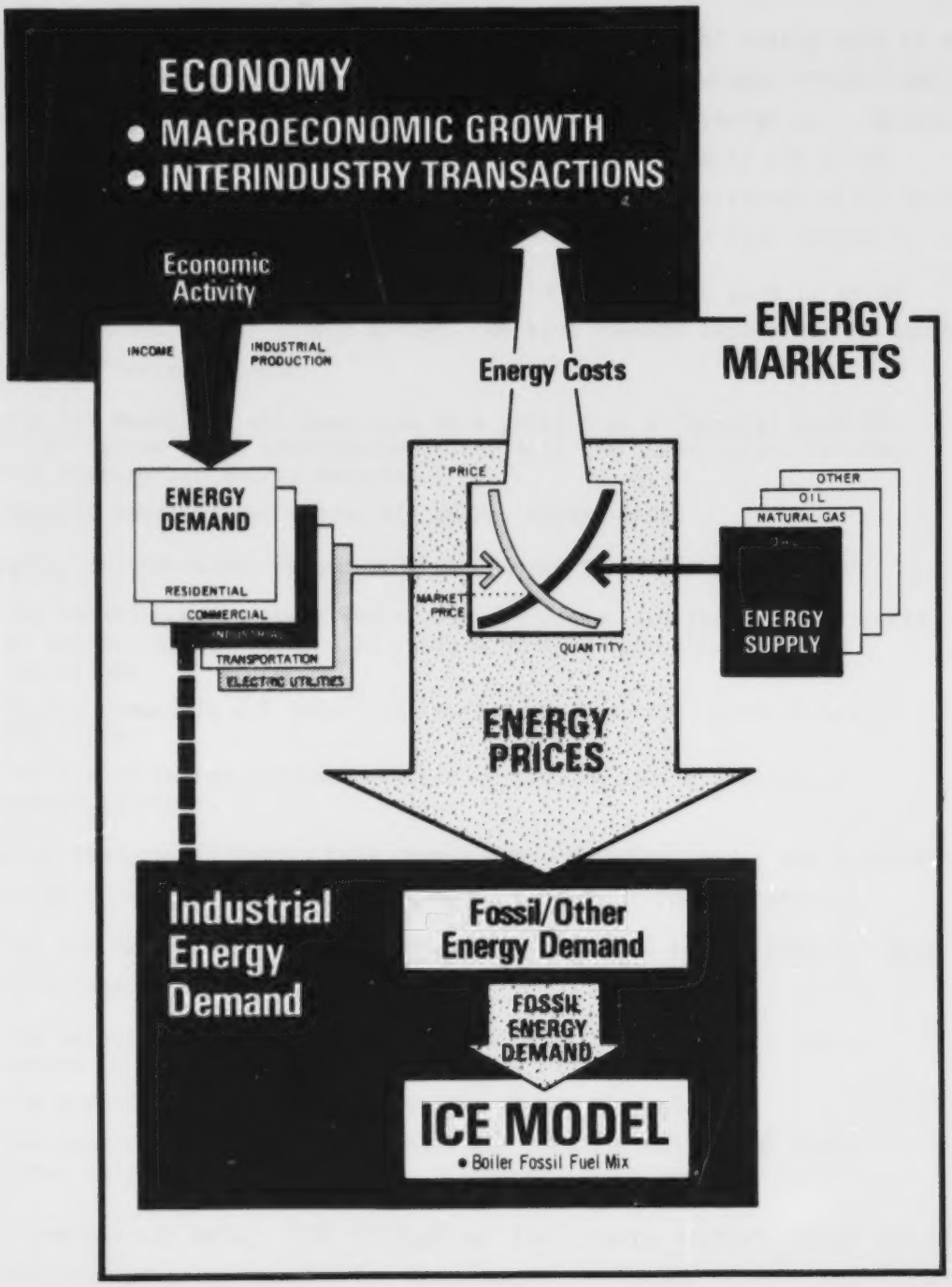

Figure 1. Context of current ICE Model structure.

In turn, the energy market trends provide the costs of energy back to the macroeconomic framework, through such variables as the Consumer Price Index and costs of energy inputs to the industrial sectors. These energy cost impacts can, in turn, alter macroeconomic trends. For example, world oil price inflation (deflation) results in major cost increases (decreases) which in turn affect industrial production growth, consumer behavior and real income.

Industrial energy demand, depicted at the bottom of Figure 1, is an important element of the energy market. We have focused separately on industrial energy demand because:

- The ICE Model has not been used as a portion of a "general equilibrium" system which simultaneously reflects the interactions between the economy and energy markets
- The ICE Model is not a complete energy demand model.

Logically, an industrial demand model addresses the following issues:

- The relationship between industrial production and the overall level of energy inputs required to perform various industrial process operations
- Energy demand in all industrial uses (e.g., boilers, process heat, feedstock)
- The mix of energy sources selected to provide the full range of energy services.

The major (exogenous) inputs to a complete energy demand model are industrial production growth trends and the prices of various forms of energy.

The ICE Model covers only a portion of industrial energy demand. Specifically, it does <u>not</u> address in any detail:

- The relationship between overall industrial production and energy demand (e.g., conservation, process efficiency trends)
- The demand for energy in non-boiler industrial uses
- The demand for energy forms other than conventional fossil fuels (fuel oil, natural gas, coal).

A predecessor model, EEA's Industrial Fuel Choice Analysis Model (IFCAM), provided the initial framework for development of the ICE Model. Key improvements incorporated within the ICE Model include the capability to:

- Update base year data to 1980
- Generate projections by State (excluding Alaska and Hawaii) out to the year 2030
- Provide pollution control retrofit options for existing industrial oil-fired and coal-fired boilers
- Select fuel types in new industrial boilers using a statistical decision criteria based on a sample of recent sales data
- Evaluate new pollution control equipment options (specifically, fluidized bed combustion and hydrated lime/duct injection)

Many of the remaining key assumptions in the ICE Model, which are presented in this report, were developed by EPA for IFCAM. IFCAM has been used by EPA to project the environmental, cost and energy impacts of alternative New Source Performance Standards for industrial boilers.[1]

MODEL CAPABILITIES

The ICE Model is a process engineering/simple accounting industrial boiler fuel choice model. This modeling technique simulates the effects of specific policies on technical alternatives through the application of direct engineering information at a disaggregated level. Other types of models include:

- Econometric (mathematical equations solved simultaneously with coefficients estimated statistically from historical data)
- Optimization (derivation of "best" solutions by means of algebraic procedures such as linear programming)
- Simulation or system dynamics (mathematical equations solved recursively with coefficients estimated from modeler's experience and intuition).

The ICE Model structure has been designed to evaluate alternative fuel price projections, government energy and environmental policy proposals, the costs associated with firing alternative fuels and other key model parameters. The fuel choice decision criterion includes a comparison of after-tax, discounted cash flows. Therefore, a variety of proposed tax credits and changes in the tax treatment of capital that provide incentives to invest in coal-related equipment can be analyzed using the model.

Environmental regulatory policies can affect fuel choice by altering the relative costs of burning alternative fuels. Regulations relating to PM, SO_2,

and NO_x emissions from fuel-burning sources include State and local regulations and Federal NSPS.

The ICE Model is capable of modeling alternative industrial boiler NSPS. The ICE Model can simulate the use of various types of flue gas desulfurization (FGD) systems (some with combined SO_2/particulate matter emissions control), various types of post-combustion particulate matter emissions control, and combustion modifications to control NO_x emissions.

Several types of alternative NSPS specifications of SO_2 emissions control for new industrial residual fuel oil or coal-fired boilers can be analyzed. For example, the regulation can vary by boiler size and can be specified as:

- A ceiling emission rate (lb of pollutant/MMBtu of fuel burned)
- A recommended percentage removal (e.g., 90 percent removal of uncontrolled SO_2 emissions)
- A recommended percentage removal and a "floor" emissions rate (e.g., 90 percent removal but no lower than 258 ng/J [0.6 lb/MMBtu])
- A minimum percentage removal to be applied if the recommended percentage removal results in controlled emission rates lower than the "floor."

The ICE Model can simulate the impact of alternative fuel price projections on industrial fuel mix. Regional fuel prices for distillate fuel oil, residual fuel oil (four sulfur classes), natural gas, and coal (up to 11 types) are considered in the model.

The fuel choice decision is sensitive to non-fuel costs of burning alternate fuels. While the best available cost data are used, the model can evaluate the impact of any alternative cost estimates.

The ICE Model's fuel choice decisions are a function of technical as well as economic and regulatory factors. The ICE Model evaluates fuel switching in existing boilers and fuel type selection in new boilers. For existing boilers, fuel choice is determined by comparing the after-tax net present value of retrofit or fuel conversion capital costs and O&M and fuel expenses. For new units, fuel choice is determined by comparing boiler and pollution control capital, O&M and fuel costs as well as other factors.

The ICE Model selects from a wide range of fuel quality options (multiple residual fuel oil and coal types) and alternative pollution control strategies. Table 1 lists alternative industrial boiler pollution control technologies in the ICE Model.

ICE MODEL VERSIONS

ICE Model development tasks were initiated in 1983. Table 2 summarizes the progress of the ICE Model development program. This report focuses on describing Version 6.0 of the ICE Model.

TABLE 1. INDUSTRIAL BOILER POLLUTION CONTROL EQUIPMENT OPTIONS IN THE ICE MODEL

Pollutant	Version 6.0
SO_2	Flue gas desulfurization Dual alkali Lime spray drying[a] Sodium once-through Hydrated lime/duct injection[a] Fluidized bed combustion[a,b]
PM	Single mechanical collector Dual mechanical collector Side stream separator Electrostatic precipitator Fabric filter
NO_x	Combustion modification Low excess air Staged combustion air

[a] Combined SO_2/PM emissions control system; includes a fabric filter.

[b] Atmospheric pressure, conventional bubbling bed.

TABLE 2. VERSIONS OF THE ICE MODEL

Version	Date Completed	New Features
1.0	9/84	New output tables
		Extend time frame from 1995 to 2000
		State-level detail
		Add existing coal-fired boilers to 1974 baseline data
		Pollution control retrofit options for existing coal-fired boilers
2.0	12/84	Preliminary fuel choice logic for new boilers
3.0	2/85	Extend time frame from 2000 to 2030
4.0	9/85	Update base year from 1974 to 1980
		Proposed NO_x NSPS for large boilers
5.0	9/86	Revised fuel choice decision logic for new boilers
		AFBC and hydrated lime/duct injection
		Revised SO_2 ("allowable") emissions output table
		PM emissions output tables
6.0	9/87	Tax Reform Act of 1986
		TSO JCL
		Promulgated PM/NO_x NSPS for large boilers

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1. Description of the Industrial Fuel Choice Analysis Model. Energy and Environmental Analysis, Inc. Arlington, Virginia. Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. May 1985.

SECTION 2

MODEL LOGIC

The analytical approach in the ICE Model is summarized in this section. Major model steps are presented and key model input requirements are identified. Model methodology and data sources are described in further detail in Sections 3 and 4.

User options are also identified in this section. This section focuses on model input requirements related to several exogenous assumptions:

- Alternative air emissions standards
- Forecasts of industrial fuel prices
- Total projected industrial boiler fossil fuel demand.

ANALYTICAL FRAMEWORK

The ICE Model focuses on industrial boiler fuel choice decisions between coal, fuel oil, and natural gas. The ICE Model does not consider feedstock energy uses (i.e., metallurgical coal or raw materials derived from petroleum or natural gas in the chemical industry), energy consumption in process heat applications or the combustion of LPG, municipal or agricultural solid waste, or non-purchased self-generated by-product fuels (i.e., wood, black liquor, coke oven gas, blast furnace gas, refinery off-gas or still gas).

Industrial boiler energy use is disaggregated by new and existing boilers of different sizes and annual capacity utilization rates. New and existing boilers are classified on the basis of the type of fuel they were designed to fire and whether they can be converted to fire alternative fuels. Eight size classes and five capacity utilization rate categories are delineated for boilers.

Figure 2 outlines the model structure and identifies key inputs and major analytical steps.

Inputs 1 and 2 - Baseline (1980) and Projected Industrial Boiler Fossil Fuel Demand: The levels of industrial boiler fossil fuel demand by State (excluding Alaska and Hawaii) and industry group are critical inputs to the ICE Model.

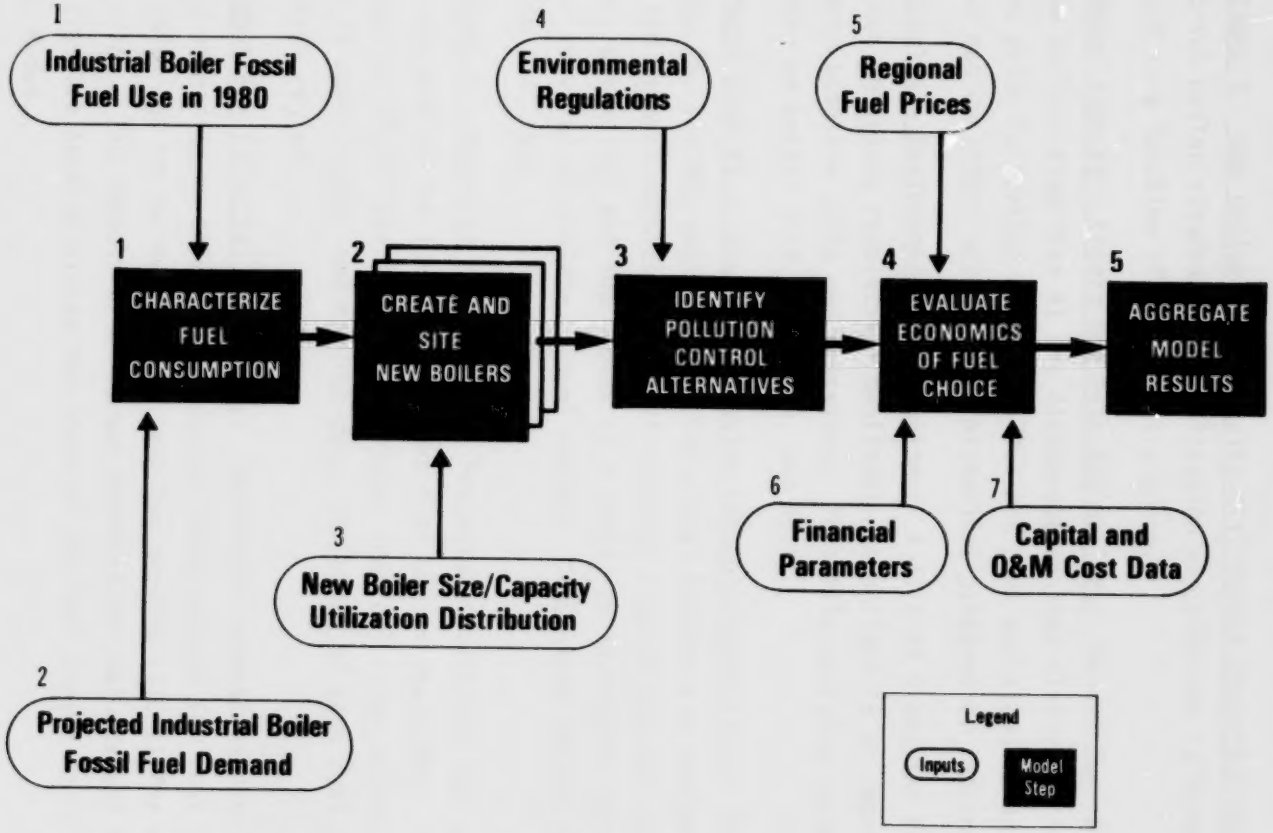

Figure 2. ICE Model structure.

Model Step #1 - Characterize Fuel Consumption: This initial step disaggregates the projected industrial boiler fossil fuel demand by new and existing facilities.

Input 3 - New Boiler Size/Capacity Utilization Distribution: The new industrial boiler size/capacity utilization distribution is based on historical data and is a function of the industry group.

Model Step #2 - Create and Site New Boilers: Fossil fuel demand forecasts for new boilers from Step #1 are disaggregated into classes of individual boilers prior to further analysis. Boilers then are sited in an Air Quality Control Region (AQCR) according to historical patterns of industrial location.

Input 4 - Environmental Regulations: A file of State and Federal air pollution emissions regulations applicable to boilers is an important input to determine baseline costs and emissions. This file contains current regulations that vary by boiler size, fuel type, and AQCR.

Model Step #3 - Identify Pollution Control Alternatives: Emission limits for SO_2, PM, and NO_x applicable to individual boilers are assigned based on State and Federal regulations. Environmental regulations may increase the capital, operating, and fuel costs of a boiler by increasing the environmental control required or quality of fuel burned. Compliance options are identified for each fuel type.

Input 5 - Regional Fuel Prices: Projected industrial fuel prices (1980-2040) are used in the ICE Model to make fuel choice decisions. Fuel prices are required for distillate fuel oil, residual fuel oil (four sulfur classes), coal (up to 11 coal types), and natural gas. The price of each fuel type can vary by Federal region.

Input 6 - Financial Parameters: Investment incentives considered have focused primarily on differential depreciation methods for coal-, oil-, or gas-fired units and on increased investment tax credits (ITC's) for coal-derived fuel firing. The impacts of different depreciation methods and investment incentives are handled within the scope of the fuel choice decision logic in the ICE Model.

Input 7 - Capital and O&M Cost Data: Capital and O&M cost data for industrial boilers and pollution control equipment are derived from detailed engineering estimates.[1] Engineering cost data are periodically revised when current estimates are refined or new estimates become available.

Model Step #4 - Evaluate Economics of Fuel Choice: Based on the characteristics of each boiler (size, operating rate, pollution control requirements, etc.), capital and annual non-fuel operating and maintenance costs are estimated for the options of choosing fuel oil, natural gas, or coal.

The cost components can be divided into three major subsets: policy inputs, standard model assumptions, and key model variables. Policy inputs are depreciation life and method, ITC, and fuel prices. Standard model assumptions are construction period and corporate tax rate. These elements do not vary by boiler characteristics and represent standard investment assumptions. Key model variables -- capital costs, investment period, discount rate, annual fuel consumption by capacity utilization rate and size, and operation and maintenance (O&M) costs -- all vary with factors considered in the model (e.g., new or existing classification or environmental regulation).

The fuel choice decision criteria for new industrial boilers are based on an analysis of recent industrial boiler orders. It is a function of boiler size, region and previous coal experience as well as net steam generation cost differences among alternative fuels. Existing industrial boilers may switch fuels and/or add pollution control equipment in response to fuel price forecasts or changes in environmental regulations.

Model Output Features: A significant amount of output detail is stored in a computer file from each ICE Model run. This file contains information for industrial fossil fuel-fired boilers in the population, including:

- Size (design firing rate)
- Annual capacity utilization rate
- State (48 contiguous)
- Industry group
- SIP
- Projected annual fuel consumption by fuel type

- Average annual controlled air emission rates
- Pollution control equipment (see Table 1)
- Capital, O&M, and fuel costs.

USER OPTIONS

Figure 3 summarizes the major ICE Model user options. "User options" are defined to be frequent user modifications to a subset of the model input files.

The ICE Model user options can be classified in two groups:

- Air emission standard specifications
- "Energy scenario" specifications.

Alternative air emissions standards for SO_2, PM, and NO_x emissions from the combustion of coal, distillate fuel oil, residual fuel oil and natural gas in new and existing industrial boilers can be selected by the user. Default values are New Source Performance Standards (NSPS) for new boilers and State Implementation Plan (SIP) standards for existing industrial boilers. Energy scenario specifications are exogenous regional projections of:

- Industrial fossil fuel prices
- Total industrial boiler fossil fuel demand.

Alternative Air Emission Standards

There are eight industrial boiler size classes in the ICE Model:

- <9 MW (<30 MMBtu/hr)
- 9-15 MW (30-50 MMBtu/hr)
- 15-22 MW (50-75 MMBtu/hr)
- 22-29 MW (75-100 MMBtu/hr)
- 29-44 MW (100-150 MMBtu/hr)
- 44-58 MW (150-200 MMBtu/hr)
- 58-73 MW (200-250 MMBtu/hr)
- >73 MW (>250 MMBtu/hr).

Model users may specify emissions ceilings by boiler size category, annual capacity utilization rate (less than or greater than 30 percent), pollutant and

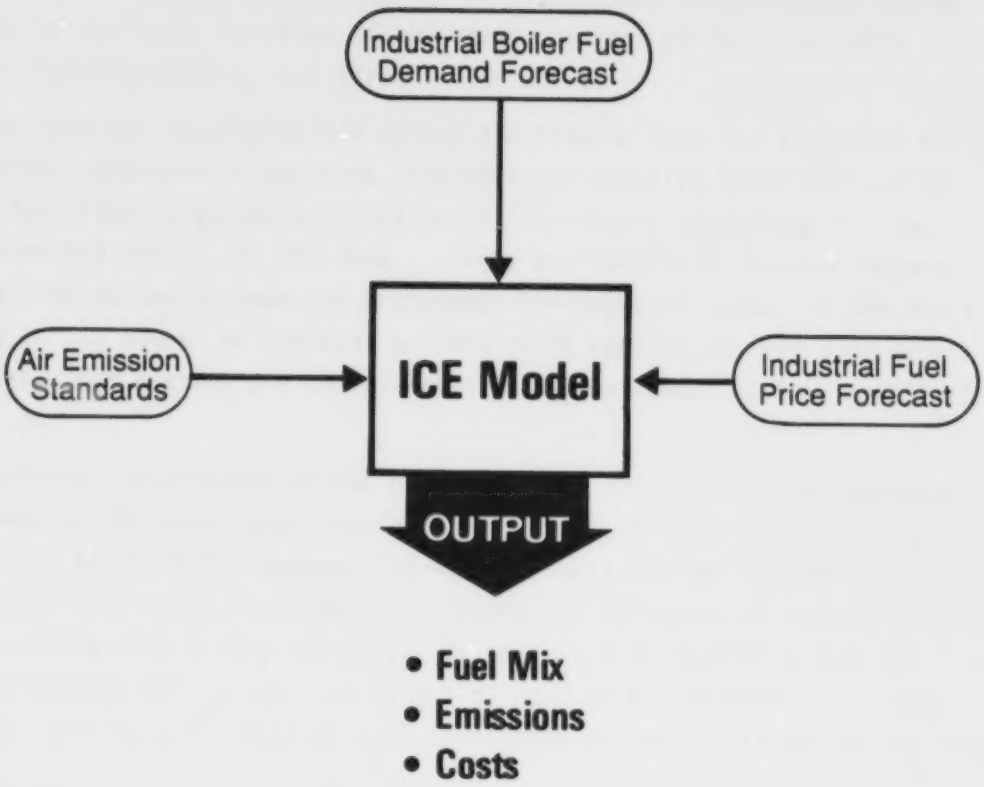

Figure 3. ICE Model user options.

fuel type (SO_2 for residual fuel oil; SO_2 and PM for coal) in terms of pounds of emissions per million Btu of fuel consumption.

Mandatory scrubbing can also be required for new industrial residual fuel oil and coal boilers by size class. The SO_2 emissions percentage removal requirement can be fixed (constant for all fuel types regardless of sulfur content) or variable (function of the sulfur content of the fuel, such as the current electric utility coal-fired boiler NSPS).

The user may also specify a market penetration rate for fluidized bed combustion. Atmospheric pressure, conventional bubbling bed fluidized bed combustion (FBC) is an optional SO_2 emissions control technology for new coal-fired boilers in the ICE Model. Users may specify a fraction between zero and one that varies by year and represents the expected number of FBC units divided by the number of new coal boilers which require SO_2 emission control equipment. FGD systems are the alternative SO_2 emissions control equipment technology.

Technical constraints on the performance of emission control equipment are considered by the model when standards are expressed as an emissions ratio (i.e., ng/J or lb/MMBtu) between the mass of emissions and the amount of energy released by the fuel. For example, a mechanical collector is assumed not to be able to comply with a very low (e.g., 22 ng/J or 0.05 lb/MMBtu) coal PM emission regulation. A very low (e.g., 86 ng/J or 0.2 lb/MMBtu) coal SO_2 emissions ceiling will restrict coal compliance options to scrubbing low sulfur coals.

Industrial Fossil Fuel Price Forecast

Projected delivered industrial fuel prices are required for the following fuel types:

- Natural gas
- Distillate fuel oil
- Residual fuel oil
  - 3.0 percent sulfur
  - 1.6 percent sulfur

- 0.8 percent sulfur
- 0.3 percent sulfur

- Coal, ng SO_2/J (lb SO_2/MMBtu)*
  - bituminous <464 (<1.08)
  - bituminous 464-718 (1.08-1.67)
  - bituminous 718-1,075 (1.67-2.50)
  - bituminous 1,075-1,432 (2.50-3.33)
  - bituminous 1,432-2,150 (3.33-5.00)
  - bituminous >2,150 (>5.00)
  - subbituminous <464 (<1.08)
  - subbituminous 464-718 (1.08-1.67)
  - subbituminous 718-1,075 (1.67-2.50).

Fuel prices are required for five-year increments (1980-2040) and by Federal region (reference Figure 4) in constant 1980 ¢/MMBtu.

Industrial Boiler Fossil Fuel Demand Forecast

Total projected industrial boiler fossil fuel demand is an exogenous parameter. "Total industrial boiler fossil fuel demand" is defined to include only the sum of:

- Natural gas
- Distillate and residual fuel oil
- Coal.

Projections are required by State (excluding Alaska and Hawaii), industry group, and year (1985, 1990, 1995, 2000, 2010, 2020, and 2030). The units are 10^{12} Btu.

There are seven industry groups in the ICE Model:

- Food
- Textiles
- Paper

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* User-specified. Up to 11 types. This list presents the nine coal types currently used in EPA's industrial boiler NSPS analysis. Reference Appendix A.

Figure 4. Federal regions of the United States.

- Chemicals
- Petroleum refining
- Primary metals
- Other industrial.

Total projected industrial boiler fossil fuel demand is an exogenous parameter because the ICE Model is one of a group of National Acid Precipitation Assessment Program (NAPAP)[2] sectoral emissions models. Input specifications for all of the NAPAP sectoral emissions models are coordinated by EPA and DOE in order that ICE Model results are comparable with other NAPAP sectoral emissions models[3].

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SECTION 3

INDUSTRIAL BOILER POPULATION CHARACTERISTICS

There are two major parts to the ICE Model:

- Project the distribution of industrial fossil fuel-fired boiler characteristics
- Select the fuel type for each unique set of characteristics.

The major industrial boiler population characteristics are discussed in this section. The fuel choice decision criteria are summarized in Section 4.

The characteristics discussed in this section include:

- New or existing status
- Size (design firing rate) and annual capacity utilization rate
- Fuel-firing capability
- Local air emissions regulations
- Pollution control compliance alternatives.

CATEGORIZATION OF BOILER FOSSIL FUEL USE BY NEW AND EXISTING FACILITIES

Significance for Modeling

The new/existing distinction is important in any process engineering analysis of fuel choice decisions since the technical capability, the nature of the investment decision, energy and environmental policies, and the costs of using alternate fuels differ for existing units and new facilities.

Existing boilers can be converted to burn oil or gas; they can be converted to coal either by reconverting units originally designed to fire coal or by accelerating replacement of existing units (that never fired coal) with new coal-fired boilers; conversion to any other fuel involves retrofitting the boiler. Retrofitting, for coal use, oil/natural gas boilers that never were designed to burn coal is impractical for two reasons. First, boiler capacity must be downrated substantially (20 to 60 percent less than the original design capacity) and second, necessary modifications to existing equipment may be physically impossible.[1]

The primary constraint to boiler modification is combustion volume. Significantly more combustion volume is required for burning coal than for burning oil or gas to insure that the flue gas temperature at the entrance to the boiler convective section is below coal's ash-softening point. Coal firing also requires additional burnout time to permit more heat absorption in the radiant (waterwall) section. If it is physically impossible or economically impractical to enlarge the furnace area, boiler capacity must be downrated substantially.

Other boiler constraints to coal conversion are convective section and air preheater redesign and the addition of sootblowers and fans. Due to these technical problems, converting existing units not originally designed to burn coal to coal firing is assumed to be infeasible unless the boiler is replaced.

An obvious example related to environmental regulations is the Federal NSPS which governs emissions from new or modified stationary sources. The NSPS are designed to reflect the degree of emission control achievable through the application of the best system of emission reduction which EPA, having taken into account the cost of control, determines to be demonstrated adequately. The Federal NSPS is the same throughout the country. The national impacts of NSPS are a function of the projected mix of new and existing facilities.

Due to varying technical problems associated with converting existing combustors to fire coal, the investment decisions and associated costs of fuel substitution differ among combustors. The following four classes of combustors each involve different technical problems, costs, and investment decisions:

- Existing coal-capable units: These combustors currently are firing oil or gas but originally were designed to use coal. Minor capital investment is needed to refurbish coal-related equipment already available in order to return to coal use. Pollution control equipment may be needed as well, depending on environmental regulations.
- Existing units designed to fire only oil and/or gas that can be retrofitted: For these combustors, it is cheaper to retrofit an existing unit to fire coal rather than to entirely replace the combustor with a new coal-fired unit. The elements of the investment decision for conversion to oil or gas are similar to those for the existing coal-capable combustor.
- Existing units designed to fire only oil and/or gas that cannot be retrofitted economically: For this class of combustors, it is more

economic to replace an existing unit with a new coal-fired unit than to retrofit the facility to fire coal.

- New facilities: For new combustors, the costs of new units for each fuel type are compared, including total capital investments and operating and fuel costs. The cost estimates for new units are based on the assumption that every new unit is a stand-alone boiler at a greenfield plant.

Approach to Allocation of Fuel Use Among New/Existing Facilities

Because projected fossil energy demand in any future year is an exogenous input, the split between energy use in new facilities and existing facilities will be determined by the exogenous growth rate in total fossil fuel demand plus the retirement rate of existing facilities.

Retirement of energy use in existing boilers can occur through reduced capacity utilization or actions that reduce fuel use to essentially zero, such as actual scrappage or a shift to standby status. The decision to retire a boiler is determined by many parameters. Over time, equipment will deteriorate and require replacement. Maintenance costs tend to increase and, depending on the type of boiler, fuel use efficiency (e.g., for a boiler, fuel input in Btu per pound of steam generated) may decline. Essentially random factors, such as the phaseout of an uneconomic plant or part of an old plant's production, also can cause a boiler to retire. In addition, the technical fuel use efficiency and cost of new boilers will affect retirement rates. Fuel costs, conservation potential, the availability of capital, and other investment demands all influence retirement rates. Logically, the decision to replace boilers depends on the economics of plant- and corporate-specific situations.

In a previous study, EEA used the concept of vintaging plus decay factors to estimate retirement or capital turnover rates.[2] This approach indicated retirement rates (percent of annual energy use retired) for boilers ranging from two to three percent.

The current boiler retirement methodology in the ICE Model is to estimate an annual capital turnover rate. The current annual retirement rate estimate is 0.62 percent of projected industrial boiler total fossil fuel demand. This estimate is based on an ABMA representative's subjective estimate that 15 percent of ABMA data on new industrial watertube boiler sales capacity repre-

sents replacement boilers. No estimate for boiler retirements without replacements is available.

Fifteen percent of the 1965-1976 average annual ABMA new industrial watertube boiler capacity sales data* is 2,369 MW (8,028 MMBtu/hr).** Assuming that the average industrial boiler capacity utilization rate is 55 percent, the level of retirement and replacement of annual watertube boiler fuel demand is 2,369 MW (8,028 MMBtu/hr) x 0.55 x 8,760 hours/year = 41 PJ (38.68 trillion Btu/year). This level of retirements represents 0.62 percent of the EEA estimate of fossil fuel consumption in industrial boilers in 1976, 6.6 TJ (6.25 quadrillion Btu). This retirement rate is applied to total industrial boiler fossil fuel demand -- small firetube boilers as well as watertube boilers.

This analysis assumes that a constant percentage of the current capital stock is retired every period. As a result, total retirement is a function not only of the retirement rate selected, but also of the rate of growth of the capital stock. This approach may overstate retirements during periods of high growth and understate retirements during periods of low growth.

The calculation procedure of the total retirement of existing boilers between 1985 and 1990 is as follows. First, total boiler fossil fuel demand in 1985 and in 1990 is estimated. Second, total boiler fossil fuel demand in every year between 1985 and 1990 is estimated by calculating the compound average annual growth rate. Third, the retirement rate is applied to the total estimated boiler fossil fuel consumption in 1986, 1987, ..., 1990 in order to determine the total amount of boiler fossil fuel demand to be retired in the 1986-1990 period.

The existing "boiler records" or inventory in the ICE Model are not individual units but groups or classes of boilers. Each group is defined by location (States), fuel type, size class (eight), capacity utilization class (five), industry group (seven), new/existing status, and air emission regulation. The ICE Model projects total boiler fuel demand in a future year, multiplies this value by $(1.0062)^a - 1$ (where a = forecast year - base year),

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*Domestic orders for manufacturing industries only.

**Assuming 1,250 Btu/lb steam.

and subtracts this fuel demand proportionately from each group of boilers which existed in the base year (currently 1980). Boilers installed after 1990 are not retired. Boilers installed between 1980 and 1985 are not retired until after 2010. Boilers installed between 1985 and 1990 are not retired until after 2020.

It is assumed that the load factor is constant over the life of the unit on an annual basis. That is, changing steam requirements are met by retiring existing units and adding enough new units to meet the total projected steam demand requirements.

Each boiler fuel choice decision is evaluated independently. Costs at a plant (as a whole) are not minimized. Fuel choice decisions are made as if each boiler is the only boiler at each plant. The ICE Model is not a steam plant planning optimization model. Therefore, the current boiler inventory is not characterized by plant size or type of plant. The ICE Model does not have the capability to predict future steam requirements at specific plants, and the ICE Model does not make an integrated decision to minimize total steam plant costs.

The current retirement methodology in the ICE Model does not explicitly take into account the age of equipment or the economics of continuing to use old equipment versus replacing it with new equipment. In addition, this approach does not model retirements without replacements, and, as a result, may understate the retirement rate. Furthermore, this approach assumes that boiler capacity utilization rates remain constant over time and that annual increases or decreases in steam demand are not met to some extent by changing the capacity utilization rate of the existing inventory.

One factor worth emphasizing is that EEA's approach to estimating retirement rates does not consider the effect of rising fuel costs or energy policy on the overall efficiency of energy use in existing combustors. For example, taxes on fuel use affecting existing combustors will conserve energy because higher fuel costs will promote efforts to increase the efficiency of existing units; this energy conservation, however, will not be captured by retirement rates based on historical trends. The failure of the ICE Model to consider the impact of energy policy or fuel prices on overall energy efficiency in existing

units will tend to bias fuel mix results away from coal. This bias occurs because the projected year fossil energy demand (exogenous to the ICE Model) does include the effect of higher fuel prices, for example, on overall fuel use efficiency. Since the ICE Model ignores this conservation effect in determining normal retirement rates, conservation benefits reduce fuel demand in new boilers (which have a significant coal market share in the ICE Model).

Alternatives

The age of the unit may be significant if it can be established that a maximum expected useful life can be determined (e.g., 30 or 40 years). All units then would be retired once their "age" exceeded the appropriate maximum useful life estimate. However, low usage rates, conscientious O&M practices, and refurbishment opportunities may extend the useful life. In addition, this approach does not address the situation where the unit is retired prematurely (and not resold) due to a plant closing, energy conservation, or reduced production rates.

It is feasible that an economic framework could be developed which would compare the increasing O&M costs of existing boilers with the cost of a new boiler (levelized capital plus O&M). O&M costs of existing equipment may be expected to increase because of declining efficiency, parts replacement, and increased maintenance expenses. The unit could be replaced when the average cost of a new unit is less than the average future O&M costs of the existing unit.

However, it is difficult to collect data on O&M costs for a single combustor. Plant managers are usually unable to allocate or track all labor and materials costs combustor by combustor. As a result, long-term time series data for an individual unit are not available, and estimates of increasing O&M costs over time for old units cannot be made.

If it is assumed that O&M costs do not increase in real terms over time, an economic framework still could be developed. An existing unit would never be replaced with a new unit that has the same fuel type in this analysis because the O&M costs would be identical and the levelized capital costs of the new unit would preclude the new unit from being the low cost alternative. Therefore, this approach does not focus on retirement but on "early replace-

ment" with a new fuel type. In fact, the new fuel type would always be coal. It is unlikely that a plant manager would replace a coal boiler with a new gas/oil boiler; the lower non-fuel O&M costs associated with burning gas or oil would not likely offset the capital cost of a new gas/oil boiler and the higher fuel bills.

"Early replacements" (or accelerated retirements) are not normal retirements. They are a relatively expensive fuel-switching option for coal firing. They depend to a large extent on capital availability -- capital invested to earn a return by reducing future total O&M and fuel costs. They can be considered as discretionary investments because they do not necessarily (or primarily) improve or expand production capacity. Early replacements may benefit the company by saving premium (and expensive) fuels for premium uses and switching a portion of energy purchases to fuels with a relatively better supply and price outlook (i.e., coal). In addition, an economic framework for early replacements does not address the situation where boilers are scrapped or placed on stand-by.

Plant managers match boiler capacity with seasonal and daily steam load curves. They may provide for some measure of redundant boiler capacity so that the plant can operate at partial or full production capacity in the event of an unexpected boiler shutdown. It is not possible to optimize boiler configurations at a specific plant without data on future steam load curves. However, it may be possible to develop a few generic plant types and simulate the retirement strategy for each. The problem then would be how to assign the existing boiler population to one of the generic plant types.

Ideally, the retirement methodology would be a dynamic function of the boiler age, efficiency, expectation of fuel costs over the remaining life of the unit, non-fuel O&M costs, pollution control requirements for existing and new units, capital availability, expectations of future plant increasing or decreasing steam requirements, and possibly cogeneration with a new unit. However, data on industrial boiler retirements and associated parameter values do not exist. ABMA and DOE collect data on new boiler orders, but the data do not distinguish between replacements of retired units, increased steam capacity at existing plants, and new plants. This data base also does not include data

on existing boilers which are scrapped, load reduced or placed on stand-by, or load factor increased to meet new steam demand requirements.

CLASSIFICATION OF BOILER FUEL USE BY SIZE AND CAPACITY UTILIZATION RATE

Significance for Modeling

The size and capacity utilization rate of a boiler greatly affect fuel choice decisions. Boiler size is important for several reasons. First, boiler costs are characterized by economies of scale and these directly affect the economics of fuel choice decisions. Second, pollution control strategies, often involving substantial capital and operating costs, vary by size. Third, environmental regulations, both State and Federal, often specify levels of air pollution control by boiler size. Fourth, Federal energy tax policies, investment incentives, and regulatory proposals have targeted industrial boilers of specific size ranges. To capture these implications of boiler size on fuel choice decisions, the ICE Model disaggregates boiler fuel demand into several size categories.

The capacity utilization rate of a boiler is also a critical parameter in the economics of fuel choice decisions. A capacity utilization rate represents the total Btu actually burned in a boiler during a year divided by the maximum Btu that could be burned, assuming a fixed design firing rate of the boiler and 8,760 hours of operation per year. A high capacity utilization rate gives certain capital intensive technologies (with large economies of scale) a competitive edge.

As shown in Table 3, it is assumed that new non-coal industrial watertube boilers have dual-fuel (oil/gas) firing capability, residual fuel oil/natural gas or distillate fuel oil/natural gas. All new coal-fired boilers larger than 73 MW (250 MMBtu/hr) are assumed to be pulverized coal units. New industrial coal-fired boilers between 29 MW (100 MMBtu/hr) and 73 MW (250 MMBtu/hr) are assumed to be a mix of pulverized coal and spreader stoker units. These two methods of coal combustion have different costs, flue gas flow rates and uncontrolled PM and NO_x emission rates. New industrial coal boilers between 15 MW (50 MMBtu/hr) and 29 MW (100 MMBtu/hr) are assumed to be spreader stoker units. New industrial coal-fired boilers smaller than 15 MW (50 MMBtu/hr) are assumed to be underfeed stokers. Fluidized bed combustion is also an option

TABLE 3. NEW INDUSTRIAL BOILER SIZE/TYPE ASSUMPTIONS IN THE ICE MODEL

Boiler size category MW (MMBtu/hr) heat input		Type		
Range	Representative size	Coal	Residual oil/ natural gas[a]	Distillate oil/ natural gas[a]
<9 (<30)	6 (20)	N/A	Package, firetube	Package, firetube
9-15 (30-50)	12 (40)	Package, watertube, underfeed stoker	Package, watertube	Package, watertube
15-22 (50-75)	18 (62)	Field-erected, watertube, spreader stoker	Package, watertube	Package, watertube
22-29 (75-100)	26 (87)	Field-erected, watertube, spreader stoker	Package, watertube	Package, watertube
29-44 (100-150)	37 (125)	Field-erected, watertube, spreader stoker or pulverized coal[b]	Package, watertube	Package, watertube
44-58 (150-200)	51 (175)	Field-erected, watertube, spreader stoker or pulverized coal[b]	Package, watertube	Package, watertube
58-73 (200-250)	66 (225)	Field-erected, watertube, spreader stoker or pulverized coal[b]	Two package, watertube[c]	Two package, watertube[c]
>73 (>250)	95 (325)	Field-erected, watertube, pulverized coal	Two package, watertube[c]	Two package, watertube[c]

[a] Firetubes are single-fuel fired. Watertubes are dual-fuel fired.

[b] A mix is assumed in this size class.

[c] Each one-half of the "representative size" in the second column.

for new coal-fired units. Coal is not selected for new units less than 9 MW (30 MMBtu/hr) because the cost algorithms are not well defined and the statistical fuel choice decision module is not applicable.

There are eight boiler sizes (see Table 3) and five boiler capacity utilization rate classes (25, 45, 55, 65, and 75 percent) in the ICE Model.

New Industrial Boilers

The specific boiler size/capacity utilization rate combination for individual new industrial boilers is derived by applying a frequency distribution to the total projected level of fossil fuel demand in new boilers. This distribution is based on historical data and is assumed to remain constant over time and not to vary by region.

The current distribution in the ICE Model has been derived from three sources: American Boiler Manufacturers Association (ABMA) industrial watertube boiler sales data, a PEDCo report,[3] and EPA's National Emissions Data System (NEDS). The NEDS data were used to develop a preliminary distribution of boiler fuel consumption by size category, capacity utilization class, and industry group. This preliminary distribution was normalized to correspond to PEDCo estimates of the national distribution of industrial firetube versus watertube boiler capacity in 1977. This distribution was further normalized to 1965-1980 ABMA industrial watertube boiler sales data. Therefore, the watertube boiler size distribution is based primarily on ABMA data. The mix of new firetube and watertube industrial boilers is based primarily on PEDCo estimates. The capacity utilization distribution for each size class in each industry group is based primarily on NEDS data.

This procedure was followed because of the data limitations of each data source. NEDS includes industry group, size, and capacity utilization rate information for the existing boiler inventory but does not have complete coverage for small boilers. The PEDCo estimates do not include data on industry group or capacity utilization rate. The ABMA data do not include information on capacity utilization rate.

A unique distribution has been developed for each industry group. This distribution is presented in Table 4.

TABLE 4. NEW INDUSTRIAL BOILER SIZE/CAPACITY UTILIZATION RATE DISTRIBUTION[a]

Industry group	Boiler size MW (MMBtu/hr)	Capacity utilization	Frequency
Food	6 (20)	.25	.0442
	6 (20)	.75	.0293
	12 (40)	.25	.0404
	12 (40)	.45	.0354
	12 (40)	.75	.0432
	18 (62)	.25	.0549
	18 (62)	.45	.0521
	26 (87)	.25	.0736
	37 (125)	.25	.1325
	37 (125)	.65	.0776
	51 (175)	.45	.1366
	66 (225)	.75	.0820
	95 (325)	.25	.0569
	95 (325)	.65	.1413
Paper	6 (20)	.25	.0116
	6 (20)	.75	.0138
	12 (40)	.25	.0100
	12 (40)	.45	.0149
	12 (40)	.75	.0217
	18 (62)	.25	.0360
	18 (62)	.75	.0274
	26 (87)	.25	.0247
	26 (87)	.75	.0307
	37 (125)	.45	.0555
	37 (125)	.75	.0732
	51 (175)	.45	.0585
	51 (175)	.75	.0738
	66 (225)	.45	.0534
	66 (225)	.75	.0549
	95 (325)	.25	.0548
	95 (325)	.45	.0367
	95 (325)	.55	.1163
	95 (325)	.75	.2321
Chemicals	6 (20)	.25	.0120
	6 (20)	.45	.0125
	6 (20)	.75	.0186
	12 (40)	.25	.0188
	12 (40)	.45	.0133
	12 (40)	.65	.0095
	12 (40)	.75	.0316

(Continued)

TABLE 4. (Continued)

Industry group	Boiler size MW (MMBtu/hr)	Capacity utilization	Frequency
Chemicals (cont'd)	18 (62)	.25	.0294
	18 (62)	.65	.0214
	18 (62)	.75	.0334
	26 (87)	.25	.0160
	26 (87)	.65	.0488
	37 (125)	.45	.0654
	37 (125)	.75	.0872
	51 (175)	.45	.0684
	51 (175)	.75	.0872
	66 (225)	.45	.0625
	66 (225)	.75	.0640
	95 (325)	.25	.0370
	95 (325)	.45	.0370
	95 (325)	.65	.0753
	95 (325)	.75	.1507
Textiles	6 (20)	.25	.1031
	6 (20)	.75	.0513
	12 (40)	.25	.0955
	12 (40)	.45	.0424
	12 (40)	.75	.0702
	18 (62)	.25	.0792
	18 (62)	.75	.1044
	26 (87)	.25	.1018
	37 (125)	.25	.1074
	37 (125)	.65	.1285
	51 (175)	.45	.1162
Petroleum Refining	6 (20)	.25	.0375
	12 (40)	.65	.0416
	12 (40)	.75	.1000
	18 (62)	.45	.0427
	18 (62)	.75	.0716
	26 (87)	.75	.0972
	37 (125)	.75	.0598
	51 (175)	.45	.0855
	51 (175)	.75	.1655
	95 (325)	.25	.0844
	95 (325)	.75	.2142

(Continued)

TABLE 4. (Continued)

Industry group	Boiler size MW (MMBtu/hr)	Capacity utilization	Frequency
Primary Metals	6 (20)	.75	.0138
	12 (40)	.25	.0552
	12 (40)	.55	.0265
	12 (40)	.75	.0378
	18 (62)	.45	.0521
	18 (62)	.55	.0722
	26 (87)	.45	.0446
	37 (125)	.45	.0369
	37 (125)	.75	.0467
	51 (175)	.25	.0490
	51 (175)	.65	.0424
	51 (175)	.75	.2503
	66 (225)	.75	.0352
	95 (325)	.25	.1039
	95 (325)	.75	.1334
Other	6 (20)	.25	.0517
	6 (20)	.45	.0178
	6 (20)	.55	.0214
	6 (20)	.75	.0235
	12 (40)	.25	.0611
	12 (40)	.45	.0413
	12 (40)	.75	.0349
	18 (62)	.25	.0597
	18 (62)	.65	.0793
	26 (87)	.55	.0799
	37 (125)	.25	.0571
	37 (125)	.45	.0464
	37 (125)	.65	.0535
	51 (175)	.45	.0644
	51 (175)	.75	.0413
	66 (225)	.55	.0488
	95 (325)	.45	.1087
	95 (325)	.75	.1092

[a] Energy and Environmental Analysis, Inc.

Industrial Boilers Existing in 1980

The current base year in the ICE Model is 1980. The following data elements are included in the ICE Model base year data file:

- State (48 contiguous) and Air Quality Control Region (AQCR)
- Industry group (one of seven)
- Fuel type (natural gas, distillate or residual fuel oil, or coal)
- Boiler size class (MMBtu/hr, one of eight categories)
- Annual capacity utilization rate (one of five categories)
- Annual fossil fuel consumption (million Btu/year)
- Pollution control equipment
- State Implementation Plan (SIP) air emission limits by pollutant (SO_2, PM, NO_x) and fuel type (residual fuel oil and coal)
- Controlled annual average emission rates for SO_2, sulfates, PM, and NO_x.

There are over 10,000 records in this ICE Model input file.

The base year data in the ICE Model are an estimated distribution of existing industrial fossil fuel-fired boiler characteristics, not a disclosure of proprietary data. Some of these data elements (i.e., specific boiler firing rate and actual annual fuel consumption) are proprietary data elements on EPA's National Emissions Data System (NEDS), DOE/EIA's Large Combustor Survey (Form EIA-463) and DOE's Major Fuel Burning Installation (MFBI) Survey (Form FEA C-602-S-0). Therefore, several ICE Model base year parameters (i.e., boiler size and annual capacity utilization rate) are represented as generic classes. These records are not grouped by industrial plant; records with the same industry group and AQCR do not necessarily represent boilers at one location.

NEDS and the 1974 MFBI data files are the primary data sources. Data on new industrial boiler sales, EEA's Industrial Sector Technology Use Model (ISTUM) aggregate estimates of industrial boiler fossil fuel consumption in 1980 by fuel type and Federal region and U.S. Department of Commerce estimates of fuels consumed in 1980 by State and industry group[4] were also reviewed.

The capacity utilization rate is assumed to remain constant over time. Increasing demand for boiler fuel over time is assumed to be met by building

new units, not increasing the capacity utilization rates of the existing inventory.

ENVIRONMENTAL REGULATIONS

Significance for Modeling

Environmental regulations play an important role in determining industrial fuel choice. For example, air pollution emission regulations alter relative capital and fuel costs and may preclude the use of certain fuels in boilers. Specific environmental regulations can vary according to geographic location, boiler size and type, and fuel type. Both Federal and State environmental regulations influence fuel choice.

The impact of environmental regulations is modeled in a three-step process. First, each boiler is assigned to an Air Quality Control Region (AQCR) within a State based on historical location patterns of industrial energy consumption. Second, the specific air emission limits applicable to each boiler are identified. Next, the pollution control equipment and the fuel quality required to meet emission limits are specified.

Assignment of Boilers to AQCRs

The environmental regulations that apply to any type of boiler can vary significantly from one AQCR to the next. While NSPS provisions apply equally in all parts of all regions, SIP provisions often vary among AQCR's and, in some cases, among areas within AQCRs.

Within each State, new boilers are located randomly by AQCR according to historical patterns. Within each State, a cumulative distribution function was developed for the level of fuel use in each AQCR. The distribution of fuel use among AQCR's is based on 1971 data. If AQCR #1 consumed three times as much fuel as AQCR #2 consumed, then each new boiler is three times more likely to site in AQCR #1 than in AQCR #2.

No attempt was made to model changes in industrial location patterns. Such trends are extremely difficult to identify and project and certainly were beyond the scope of this effort. Consequently, State and local environmental regulations implicitly are assumed not to influence industrial location patterns.

Assignment of Environmental Regulations to Individual Boilers

The environmental regulations used in the ICE Model are Federal and State air pollution control standards resulting from the 1970 and 1977 Clean Air Act (CAA) Amendments. This act gave the EPA the authority to establish National Ambient Air Quality Standards (NAAQS) that would protect the health and welfare of the population. Industrial sources are subject to State Implementation Plan (SIP) environmental regulations adopted to insure compliance with ambient standards. SIPs are developed by each State to implement and maintain NAAQS within its geographical area.

The CAA also gave EPA the authority to promulgate NSPS, national standards governing the air emissions from specific categories of newly constructed sources. NSPS are technology-defined Federal standards; combustors subject to NSPS must use the best available emission control technologies (BACT). Current NSPS standards apply to industrial, commercial or institutional boilers that have firing rates above 29 MW (100 MMBtu/hr) and that commenced construction after the dates shown in Table 5. For any unit of this type, the current NSPS is the binding regulation unless the applicable SIP for any given unit is more stringent -- hence binding -- than the NSPS. The current NSPS for industrial fossil fuel-fired boilers is under scrutiny by EPA to determine the need for, and extent of, revisions to the regulation.

State and Federal regulations can vary by fuel type. Regulations applicable to boilers that fire one of the following fuels are considered in the ICE Model: coal, residual fuel oil, distillate fuel oil, and natural gas. Regulations limiting SO_2, PM, and NO_x emissions are assumed to apply to coal- and residual oil-fired boilers. In the ICE Model, distillate oil- and natural gas-fired boilers are subject only to NO_x emissions regulations since units firing these fuels emit insignificant levels of SO_2 and PM.

New Boilers Subject to NSPS--

All new industrial boilers with firing rates greater than 29 MW (100 MMBtu/hr heat input) are currently subject to NSPS provisions. Coal-, oil-, and natural gas-fired units are subject to the NSPS air emissions limitations.

The ICE Model applies these limitations to new units that are not subject to more stringent SIP's.

On November 25, 1986 (51 FR 42769), EPA promulgated revised NSPS for PM and NO_x emissions from large new industrial boilers. Table 5 summarizes the current industrial boiler NSPS. Lignite-fired industrial boilers are not currently represented in the ICE Model. It is also assumed in the ICE Model that all new mass-feed stoker coal-fired boilers will be smaller than 29 MW (100 MMBtu/hr) and, therefore, not subject to the new NO_x NSPS presented in Table 5. Table 6 presents the industrial boiler NSPS assumptions in the ICE Model.

The revised PM NSPS for coal includes a requirement for an opacity monitor. The revised NO_x NSPS includes a requirement for a NO_x monitor for coal and high (>0.3 percent) nitrogen content residual fuel oil. If the new boiler size is larger than 73 MW (250 MMBtu/hr), the revised NO_x NSPS requires a NO_x monitor for natural gas and distillate fuel oil.

For new units that come on-line after 1985, the model can evaluate several regulatory alternatives related to coal and residual fuel oil SO_2 NSPS. For example, it can evaluate the effect of expanding the size applicability of the regulation to include new small units. The ICE Model can also evaluate the effects of a pollutant percentage reduction requirement or a change in stringency from the current NSPS. For example, the regulation for controlling SO_2 emissions from new industrial residual fuel oil or coal-fired boilers can vary by boiler size and can be specified as the following:

- A ceiling emission rate (pound of pollutant/MMBtu of fuel burned)
- A recommended percentage removal (e.g., 90 percent removal of uncontrolled SO_2 emissions)
- A recommended percentage removal and a "floor" emission rate (e.g., 90 percent removal but no lower than 258 ng/J, 0.6 lb/MMBtu)
- A minimum percentage removal to be applied if the recommended percentage removal results in controlled emission rates less than the "floor."

The coal NSPS SO_2 ceiling emission limits are assumed to be based on a 30-day rolling average, not on an annual average. Due to the variability of

TABLE 5. INDUSTRIAL BOILER NSPS[a]
ng/J (lb/MMBtu)

Pollutant	Boiler Size MW (MMBtu/hr)	Construction Commenced	Natural Gas	Fuel Oil	Coal
SO_2	>73 (>250)	after 8/18/71	--	344 (0.8)	516 (1.2)
	>29 (>100)	after 6/19/86	--	344 (0.8)[b,c]	516 (1.2)[b,c]
				172 (0.4)[b,d]	258 (0.6)[b,d]
PM	>73 (>250)	after 8/18/71 & before 6/20/84	--	43 (0.1)	43 (0.1)
	>73 (>250)	after 6/19/84	--	43 (0.1)	22 (0.05)[e]
	29-73 (100-250)	after 6/19/84	--	--	22 (0.05)[e]
NO_x	>73 (>250)	after 8/18/71 & before 6/20/84	86 (0.2)	86 (0.2)	300 (0.7)
	>29 (>100)	after 6/19/84	43 (0.1)[f]	43 (0.1)[f,g]	300 (0.7)[h]
			86 (0.2)[i]	86 (0.2)[g,i]	258 (0.6)[j]
				130 (0.3)[f,k]	215 (0.5)[l]
				170 (0.4)[i,k]	340 (0.8)[m]

[a] 40 CFR 60, Subpart D.

[b] Proposed (51 FR 22384); final rule due in December 1987.

[c] 90 percent reduction in SO_2 emissions is required; for oil-firing, SO_2 emissions do not need to be reduced below 86 ng/J (0.2 lb/MMBtu).

[d] Applicable to emerging technologies -- 50 percent reduction in SO_2 emissions is required; for oil-firing, SO_2 emissions do not need to be reduced below 86 ng/J (0.2 lb/MMBtu).

[e] 86 ng/J (0.2 lb/MMBtu) if 29-73 MW (100-250 MMBtu/hr) and if the annual capacity utilization rate is 30 percent or less and if construction commenced between June 19, 1984 and November 25, 1986.

[f] If the maximum design heat release rate is 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

[g] Distillate fuel oil only.

[h] Pulverized coal-fired only.

[i] If the maximum design heat release rate is greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

[j] Spreader stoker and fluidized bed combustion coal-fired. Also lignite not included in footnote m.

[k] Residual fuel oil only.

[l] Mass-feed stoker coal-fired.

[m] Lignite mined in N.Dak., S. Dak. or Montana; burned in a slag tap type furnace.

TABLE 6. INDUSTRIAL BOILER NSPS ASSUMPTIONS IN THE ICE MODEL
ng/J (lb/MMBtu)

Pollutant	Boiler size MW (MMBtu/hr)	Natural gas	Distillate fuel oil	Residual fuel oil	Coal
SO_2	All	--	--	User option	User option
PM	<73 (<250)	--	--	--	User option
	>73 (>250)	--	43 (0.1)	43 (0.1)	User option
NO_x	>29 (>100)	86 (0.2)[a]	86 (0.2)[a]	170 (0.4)[a]	300 (0.7)[b]
					258 (0.6)[c]

[a] Boilers in the ICE Model are packaged units with high heat release rates.

[b] Pulverized coal-fired.

[c] Spreader stoker coal-fired.

the sulfur and heat content in coal, 30-day rolling average emission rates can exceed annual average emission rates.

Variability in SO_2 emission rates exists when burning coal without a scrubber. This variability is due to many factors, including the lack of uniformity in coal seams (geological or natural factors), as well as coal mining, processing, cleaning, transportation and storage practices which may result in some degree of "blending" or mixing.

EPA has adopted a continuous 30-day rolling averaging period (recomputed daily) for drafting SO_2 NSPS for coal boiler combustion sources. EPA believes that this is long enough to minimize variability (variability declines as the averaging period increases), in order to yield results that are representative of real performance, but also permits timely enforcement (i.e., daily) of compliance with standards.[5]

EPA has estimated a ratio of about 1.20 between the maximum expected daily average SO_2 emission rate (computed from 30 days of data) and the long-term (i.e., annual) average emission rate.[6] This ratio is used in the ICE Model to determine compliance coal types.* If the annual average emission rate of a particular coal type times 1.20 is less than the 30-day rolling average SO_2 NSPS emission ceiling, then the coal type is a compliance coal type.

Table 7 shows the relationship between "compliance" coal types and alternative NSPS SO_2 ceiling emission limits. The left-hand columns in this table represent the average uncontrolled SO_2 emission rates for industrial coal types which have been used in the ICE Model. If the alternative NSPS is greater than or equal to 2,880 ng SO_2/J (6.7 lb SO_2/MMBtu), then all six coal types are compliance coal types (scrubbers are not required). If the alternative NSPS is greater than 516 ng SO_2/J (1.2 lb SO_2/MMBtu) and less than 731 ng SO_2/J (1.7 lb SO_2/MMBtu), only one (the first) coal type in Table 7 is in compliance. If the alternative NSPS is less than 516 ng/J (1.2 lb SO_2/MMBtu), all of the coal types shown in Table 7 must be scrubbed.

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* Based on a confidence level that would predict only one exceedence of the emission limit in ten years of continuous operation.

TABLE 7. COMPLIANCE COAL TYPES
ng SO_2/J (lb SO_2/MMBtu)

Annual average emissions rate[a]	Minimum 30-day rolling average emissions limit[b]
408 (0.95)	516 (1.2)
593 (1.38)	731 (1.7)
894 (2.08)	1,075 (2.5)
1,225 (2.85)	1,505 (3.5)
1,784 (4.15)	2,150 (5.0)
2,382 (5.54)	2,880 (6.7)

[a] See Table A-1.

[b] 1.2 x the annual average emissions rate.

Boilers Subject to SIPs--

All existing and new boilers are subject to SIPs. Larger new boilers subject to SIPs more stringent than the current NSPS also must abide with SIP regulations. SIP limits on SO_2, PM, and NO_x emissions vary substantially within and among States, both in the severity of the standards and in the way they are expressed. Some States specify standards only in terms of ambient conditions. Most States, however, specify standards in a variety of forms including pounds of pollutant per energy release of the fuel (lb/MMBtu), pounds of pollutant emitted per 1,000 pounds of steam, or pollutant content of the fuel, by weight, in percentage terms. In many States, SIP requirements also vary by fuel type and boiler size.

A set of regulations reflecting the diversity of SIP requirements has been compiled for use in the ICE Model. These SIPs are identified by AQCR and boiler fuel type (coal or residual fuel oil) and are specified as pounds of pollutant emitted per million Btu of fuel burned. Since a number of AQCRs contain portions of two, three, or four States, average SIPs are calculated for interstate AQCRs. Each State's SIP regulation is weighted by the fuel consumption within the State's geographical portion of the AQCR, and these weighted SIPs are averaged to estimate one interstate regulation. SIP values also are approximated for states in which SIP regulations vary by city or county, averaging period, form of specification, or boiler size class applicability.

SIPs in the ICE Model are classified among three boiler size categories: less than 29 MW (100 MMBtu/hr), 29-73 MW (100-250 MMBtu/hr), and greater than 73 MW (250 MMBtu/hr). For each size class, the regulation in the SIP file is expressed as: $E = a(X^b) + c$, where X is the boiler firing rate (MMBtu/hr heat input) and E is expressed in terms of lb/MMBtu. This form permits estimating the applicable regulation for a specific boiler size instead of using an average value.

An ICE Model user option is "SIP rollback." Nationwide SO_2 emission ceilings can be imposed on existing industrial residual fuel oil and coal boilers in the ICE Model. This SIP rollback methodology overrides SO_2 SIPs if it is more stringent than SO_2 SIPs. This can be specified by fuel type (residual fuel oil and coal) and by boiler size class.

The current SIPs in the ICE Model (and the user-option SIP modifications) for coal-fired SO_2 emission limits are assumed to be on an annual average basis. The SIP file is current as of July 1980 for PM and NO_x emissions and is current as of March 1983 for SO_2 emissions.

POLLUTION CONTROL STRATEGIES

To comply with air pollution emission regulations, boiler owners assess control strategies based upon available fuels and pollution control equipment. The control strategy employed by boiler owners depends upon the amount of emission reduction required to meet applicable regulations. Boiler owners can choose to burn a fuel grade whose uncontrolled emissions rates are within the limits established by the standards or a particular fuel grade in combination with pollution control equipment as their control strategy.

Many emission control standards necessitate the use of pollution control technologies. Several options are available in the ICE Model (see Table 8).

Coal-Fired Boilers

Control strategies for industrial coal-fired boilers include the use of one of up to 11 coals, four types of FGD equipment, fluidized bed combustion, five types of particulate matter emissions collection equipment, and two types of NO_x combustion modification.

Combustion of a boiler's compliance coal type represents a control strategy when the coal-fired uncontrolled pollutant emissions are lower than the level allowed by emission regulations. Fuels associated with allowable emission rates without the application of pollution control equipment are referred to as compliance fuels.

A wide array of coal grades has been included in the ICE Model for two reasons. First, the range of coal grades reflects the wide range of grades available. Second, since SIP regulations for SO_2 control vary significantly in stringency from one area to the next, the availability of numerous potential compliance coals should lead to a reasonable portrayal of compliance costs.

Model users may specify the industrial coal characteristics in the ICE Model. There may be as many as 11 types per Federal region. The average

TABLE 8. INDUSTRIAL BOILER POLLUTION CONTROL EQUIPMENT OPTIONS IN THE ICE MODEL

Pollutant	Technology
SO_2	Flue gas desulfurization
	Dual alkali
	Lime spray drying[a]
	Sodium once-through
	Hydrated lime/duct injection
	Fluidized bed combustion[a,b]
PM	Single mechanical collector
	Dual mechanical collector
	Side stream separator
	Electrostatic precipitator
	Fabric filter
NO_x	Combustion modification
	Low excess air
	Staged combustion air

[a] Combined SO_2/PM emissions control system; includes a fabric filter.

[b] Atmospheric pressure, conventional bubbling bed.

sulfur, ash, and Btu content may vary by Federal region. Appendix A summarizes the characteristics of the nine industrial coal types currently used in EPA's industrial boiler NSPS analysis. The average sulfur content of each of the nine coal types does not vary by region in this example. The average ash and Btu contents do vary by region for each of the nine coal types. All nine coal types are not available in all ten Federal regions. Those coal types which are not available (or are not applicable) do not have average ash and Btu content values in Tables A-2 through A-5. These coal types may be used in the ICE Model or users may modify these characteristics.

Among the most effective equipment available to control SO_2 emissions is flue gas desulfurization (FGD), or scrubbers. The types of FGD systems in the ICE Model are dual alkali, sodium once-through, hydrated lime/duct injection (including a fabric filter)[7] and lime spray drying (including a fabric filter)[8]. The scrubber cost estimates are unique for each coal type and SO_2 emission regulation. Limits on SO_2 emissions control efficiency for each FGD system are presented in Table 9.

Routine process variations in SO_2 emissions also result when operating a scrubber. The variability of FGD outlet emissions is lower than the variability of the inlet emissions. However, when the outlet variation is expressed as a percentage of the controlled emissions, the value of the resultant numerical factor is more than 1.20. EPA has estimated that this variability factor is 1.30 for typical FGD systems during routine operation. This estimate is based on an analysis of SO_2 emissions data emitted by eleven electric utility bolier FGD systems[9]. This analysis shows that to consistently obtain 90 percent removal (30-day rolling average), a geometric mean (median) scrubbing efficiency of 92.3 percent must be attained by the FGD system (Ref. 9, Exhibit 2-23). This estimate is based on an autocorrelation factor of 0.6 which was typical for these data, a daily standard deviation (log normal) of 0.20 which is representative of a well controlled FGD process, and a high level of confidence (99.97%) that projects no more than one 30-day average less than 90 percent in 10 years. A second analysis of three industrial boiler FGD systems indicated that the data were autocorrelated by a factor of 0.08 to 0.13. Thus, a 90 percent reduction standard could be achieved with as little as 91.0 percent median scrubbing efficiency[10]. The more conservative estimate of 92.3 percent

TABLE 9. FGD TECHNOLOGY CONSTRAINTS IN THE ICE MODEL[a,b]

Technology	Limits
Dual alkali	Up to 90 percent removal of uncontrolled SO_2 emissions for all coal types
Lime spray drying	Up to 90 percent removal of uncontrolled SO_2 emissions for low sulfur coal types (less than 1.67 lb SO_2/MMBtu annual average); not applicable to higher sulfur coal types regardless of the required sulfur removal rate
Sodium once-through	Up to 90 percent removal of uncontrolled SO_2 emissions for all coal types
Hydrated lime/duct injection[c]	Up to 75 percent removal of uncontrolled SO_2 emissions for all coal types

[a] U.S. Environmental Protection Agency.

[b] 30-day, rolling average basis, minimum daily removal.

[c] Not applicable to underfeed stokers - - in the ICE Model, not applicable to boiler sizes less than 15 MW (50 MMBtu/hr).

was chosen to provide adequate FGD system operating flexibility and to avoid underestimating the capital and annualized cost of the FGD system operation. Using a 92.3 percent median removel, the variability factor for FGD outlet emissions is derived as follows:

$$\frac{1 - \frac{90.0}{100}}{1 - \frac{92.3}{100}} = 1.30$$

If scrubbing is required on all new coal-fired boilers or if a coal type is not in compliance with a SIP or an alternative Federal SO_2 emissions standard (and, therefore, a scrubber is required), the annual average controlled SO_2 emissions rate is calculated as follows:

- o Example 1
  - uncontrolled annual average emission rate is 2,382 ng SO_2/J (5.54 lb SO_2/MMBtu)
  - emission standard is 90 percent SO_2 emissions removal (i.e., a minimum of 90 percent, 30-day rolling average)
  - controlled emissions:
    - -- maximum 30-day rolling average = 2,382 x (1.00 - 0.90) = 238 ng/J (0.554 lb/MMBtu)
    - -- long-term average of 30-day rolling averages = 238/1.3 = 183 ng/J (0.426 lb/MMBtu)
  - average percent SO_2 emissions removal = 100x(2,382 - 183)/(2,382) = 92.3 percent
- o Example 2
  - uncontrolled annual average emission rate is 1,225 ng SO_2/J (2.85 lb SO_2/MMBtu)
  - emission standard is 90 percent SO_2 emissions removal; when controlled emissions are less than 258 ng/J (0.6 lb/MMBtu), then the emission standard is 70 percent SO_2 emissions removal; 1,225 x (1 - 0.9) = 122.5; since 122.5 is less than 258, a minimum of 70 percent removal is required

- controlled emissions:
  - -- maximum 30-day rolling average = 258 ng/J (0.60 lb/MMBtu)
  - -- long-term average of 30-day rolling averages = 258/1.3 = 198 ng/J (0.462 lb/MMBtu)
- average percent SO_2 emissions removal = 100 x (1,225 - 198/1,225) = 83.8 percent.

o Example 3

- uncontrolled annual average emission rate is 408 ng SO_2/J (0.95 lb SO_2/MMBtu)
- emission standard is 90 percent SO_2 emissions removal; when controlled emissions are less than 258 ng/J (0.6 lb/MMBtu), then the emission standard is 70 percent SO_2 emissions removal; 408 x (1 - 0.9) = 40.8; since 40.8 is less than 258, a minimum of 70 percent removal is required
- controlled emissions:
  - -- maximum 30-day rolling average = 408 x (1.00 - 0.70) = 122 ng/J (0.285 lb/MMBtu)
  - -- long-term average of 30-day rolling averages = 122/1.3 = 94 ng/J (0.219 lb/MMBtu)
- average percent SO_2 emissions removal = 100 x (408 - 94/408) = 76.9 percent.

If the applicable SO_2 emission regulation requires a percentage reduction in emissions from coal-fired boilers (as in the three examples shown above), then the annual level of SO_2 emissions is estimated as follows:

$$\text{Annual } SO_2 \text{ emissions rate} = (R \times S) + [(1-R) \times A]$$

where S = estimated controlled annual average SO_2 emission rate

R = scrubber reliability factor (fraction)*

A = uncontrolled SO_2 emissions rate from natural gas combustion (backup fuel)

This calculation assumes a reliability factor for scrubbers and a low sulfur

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* 0.95 for dual alkali, hydrated lime/duct injection and sodium once-through FGD systems; 0.90 for lime spray drying scrubbers.

fuel standby option in the event of pollution control equipment malfunction. The costs of using backup fuels are also determined by the ICE Model.

Atmospheric pressure, conventional bubbling bed fluidized bed combustion (AFBC) is a SO_2 emissions control technology option in the ICE Model. EPA assumes that this technology can remove up to 90 percent of uncontrolled SO_2 emissions on all coal types.[11]

Uncontrolled PM emission rate estimates are a function of the ash content and heating value of the coal and the type of combustion:

- Underfeed stoker, flyash = 25 percent of the total ash content of the coal
- Spreader stoker, flyash = 65 percent of the total ash content of the coal
- Pulverized coal, flyash = 80 percent of the total ash content of the coal.

The balance is bottom ash.[12]

Seven PM emissions control technologies are available in the ICE Model for industrial coal-fired boilers. Technical limits on pollution control efficiency for each are listed in Table 10. These limits are based on data compiled by the U.S. EPA during development of revised NSPS for industrial boilers.

The controlled PM emission rate estimates for new industrial coal-fired boilers are estimated by EPA to be equal to "B" times the applicable PM emission regulation. The factor, B, varies by control technology:

- Single mechanical collector: B = 1.5
- Dual mechanical collector: B = 1.2
- Side stream separator: B = 0.8
- Electrostatic precipitator: B = 0.6.

For a fabric filter, the controlled PM emission rate estimate is a constant, 0.6 x 21 ng/J (0.05 lb/MMBtu) = 13 ng/J (0.03 lb/MMBtu).

NO_x emissions control strategies in the ICE Model include two types of combustion modifications: low excess air and staged combustion air. Table 11 summarizes the expected NO_x emission reductions.

TABLE 10. PM EMISSIONS POLLUTION CONTROL TECHNOLOGY CONSTRAINTS IN THE ICE MODEL[a]

Technology	Minimum PM emission standard
Single mechanical collector	
Stoker/bituminous coal	172 ng/J (0.40 lb/MMBtu)
Stoker/subbituminous coal	344 ng/J (0.80 lb/MMBtu)
Pulverized/all coal types	430 ng/J (1.00 lb/MMBtu)
Dual mechanical collector	
Stoker/bituminous coal	129 ng/J (0.30 lb/MMBtu)
Stoker/subbituminous coal	258 ng/J (0.60 lb/MMBtu)
Pulverized/all coal types	344 ng/J (0.80 lb/MMBtu)
Side stream separator	
Stoker/bituminous coal	64 ng/J (0.15 lb/MMBtu)
Stoker/subbituminous coal	129 ng/J (0.30 lb/MMBtu)
Pulverized/all coal types	172 ng/J (0.40 lb/MMBtu)
Electrostatic precipitator	21 ng/J (0.05 lb/MMBtu)
Fabric filter[b]	21 ng/J (0.05 lb/MMBtu)
Dual alkali FGD/single mechanical collector	
High sulfur coal (>3.5 lb SO_2/MMBtu)	129 ng/J (0.30 lb/MMBtu)
Other coal types (<3.5 lb SO_2/MMBtu)	42 ng/J (0.10 lb/MMBtu)

[a] U.S. Environmental Protection Agency.

[b] Lime spray drying FGD, atmospheric fluidized bed combustion and hydrated lime/duct injection technologies in the ICE Model each have a fabric filter.

TABLE 11. NO_x EMISSION RATE ESTIMATES FOR INDUSTRIAL COAL-FIRED BOILERS[a]

	Uncontrolled emission rate		Controlled emission rate		
	ng/J	(lb/MMBtu)	ng/J	(lb/MMBtu)	Control technology
Underfeed stoker	172	(0.40)	138	(0.32)	Low excess air
Spreader stoker	286	(0.665)	204	(0.475)	Low excess air
Pulverized coal	387	(0.90)	249[b]	(0.58)[b]	Staged combustion air

[a] U.S. Environmental Protection Agency.

[b] 288 ng/J (0.67 lb/MMBtu) for low excess air.

Oil/Gas Boilers

Control strategies in the ICE Model for industrial residual fuel oil-fired boilers include the use of a compliance oil type, a dual alkali or sodium once-through FGD system, an electrostatic precipitator for particulate emissions control, and low excess air and staged combustion air for NO_x emissions control. Uncontrolled SO_2 and PM emission rate estimates are presented in Table 12. Low excess air is the only pollution control technology in the ICE Model for control of natural gas and distillate fuel oil NO_x emissions. Boilers firing these fuels emit insignificant levels of SO_2 and PM (see Table 12). Table 13 summarizes the potential NO_x emission reduction estimates in the ICE Model for new industrial boilers burning natural gas or fuel oil.

Low NO_x burners are another NO_x emissions control technique. EPA has determined that low NO_x burners (or staged combustion burners) are considered to be a demonstrated NO_x emissions control technique for natural gas- and distillate oil-fired boilers (49 FR 25111). However, low NO_x burners are not a current pollution control equipment option in the ICE Model Version 6.0.

Summary

Table 14 presents examples of the number of pollution control compliance alternatives in the ICE Model. Uncontrolled air emission rates, SIP's, applicable NSPS, and pollution control equipment technical capabilities are compared and feasible alternatives are identified.

Table 14 shows that as many as four to seven pollution control strategies are available for a single fuel type. Consider high sulfur bituminous coal in this example. Pollution control alternatives include:

- DA/SMC and SCA
- DA FGD, ESP, and SCA
- AFBC and SCA
- DA FGD, FF, and SCA
- NaTH FGD, ESP, and SCA
- NaTH FGD, FF, and SCA.

TABLE 12. INDUSTRIAL OIL/GAS BOILER UNCONTROLLED SO_2 AND PM EMISSION RATE ESTIMATES
ng/J (lb/MMBtu)

Fuel type	SO_2	PM
Natural gas	0.26 (0.0006)	4 (0.01)
Distillate fuel oil	86 (0.2)	6 (0.0144)
Residual fuel oil		
3.0 percent sulfur	1,380 (3.21)	99 (0.23)
1.6 percent sulfur	735 (1.71)	56 (0.13)
0.8 percent sulfur	344 (0.80)	34 (0.08)
0.3 percent sulfur	138 (0.32)	17 (0.04)

TABLE 13. NO_x EMISSION RATE ESTIMATES FOR INDUSTRIAL OIL/GAS BOILERS[a]

Fuel type	Boiler size class MW	(MMBtu/hr)	Annual capacity utilization rate (percent)	Preheat temperatures	Uncontrolled annual average NO_x emission rate ng/J (lb/MMBtu)	Controlled annual average NO_x emission rate ng/J (lb/MMBtu)	NO_x control technology
Natural gas	29-44	(100-150)	≥65	400°F	112 (0.26)	82 (0.19)	Low excess air
	44-73	(150-250)	≥45	400°F	112 (0.26)	82 (0.19)	Low excess air
	>73	(>250)	All	400°F	112 (0.26)	82 (0.19)	Low excess air
	29-44	(100-150)	<65	100°F	64 (0.15)	52 (0.12)	Low excess air
	44-73	(150-250)	<45	100°F	64 (0.15)	52 (0.12)	Low excess air
	9-20	(30-100)	All	100°F	64 (0.15)	54 (0.125)	Low excess air
	4-9	(15-30)	All	100°F	60 (0.14)	47 (0.11)	Low excess air
	<4	(<15)	All	100°F	60 (0.14)	39 (0.09)	Low excess air
Distillate fuel oil	29-44	(100-150)	≥65	400°F	107 (0.25)	75 (0.175)	Low excess air
	44-73	(150-250)	≥45	400°F	107 (0.25)	75 (0.175)	Low excess air
	>73	(>250)	All	400°F	107 (0.25)	75 (0.175)	Low excess air
	29-44	(100-150)	<65	100°F	77 (0.18)	52 (0.12)	Low excess air
	44-73	(150-250)	<45	100°F	77 (0.18)	52 (0.12)	Low excess air
	9-29	(30-100)	All	100°F	96 (0.22)	67 (0.155)	Low excess air
	<9	(<30)	All	100°F	118 (0.275)	86 (0.2)	Low excess air
Residual fuel oil							
3.0% S (0.44% N)	All		All	400°F	196 (0.455)	105 (0.245)	Staged combustion air
1.6% S (0.23% N)	All		All	400°F	131 (0.305)	95 (0.22)	Staged combustion air
0.8% S (0.12% N)	All		All	400°F	97 (0.225)	84 (0.195)	Low excess air
0.3% S (0.04% N)	All		All	400°F	75 (0.175)	62 (0.145)	Low excess air

[a] U.S. Environmental Protection Agency.

TABLE 14. EXAMPLES OF POLLUTION CONTROL COMPLIANCE ALTERNATIVES IN THE ICE MODEL

Fuel type	Pollution control equipment
Natural gas	Low excess air
Distillate fuel oil	Low excess air
Residual fuel oil	
3.0% S	Low excess air
1.6% S	Low excess air
0.8% S	Low excess air
0.3% S	Low excess air
Coal, bituminous (lb SO_2/MMBtu)	
<1.08	ESP or FF; SCA
1.08-1.67	LSD FGD; AFBC; DA or NaTH FGD with FF or ESP; DA/SMC; HDLI; SCA
1.67-2.50	AFBC; DA or NaTH FGD with FF or ESP; DA/SMC; HDLI; SCA
2.50-3.33	AFBC; DA or NaTH FGD with FF or ESP; DA/SMC; SCA
3.33-5.00	AFBC; DA or NaTH FGD with FF or ESP; SCA
>5.00	AFBC; DA or NaTH FGD with FF or ESP; SCA
Coal, subbituminous (lb SO_2/MMBtu)	
<1.08	ESP or FF; SCA
1.08-1.67	LSD FGD; DA or NaTH FGD with FF or ESP; DA/SMC; HDLI; SCA
1.67-2.50	DA or NaTH FGD with FF or ESP; DA/SMC; HDLI; SCA

ESP - electrostatic precipitator
FF - fabric filter
SMC - single mechanical collector
SCA - staged combustion air
LSD - lime spray drying
DA - dual alkali
NaTH - sodium once-through
AFBC -atmospheric fluidized bed combustion
HLDI -hydrated lime/duct injection

The number of pollution control alternatives is not constant. It varies with the boiler size, fuel type, and environmental regulations.

The examples shown in Table 14 indicate that the ICE Model compares costs for a large number of fuel type/pollution control equipment configurations. Table 14 summarizes examples; Table 14 does not list all of the possible combinations in the ICE Model.

Sulfate Emission Factors

Table 15 presents the SO_4 emission factors that are being used in the ICE Model. The factors are expressed in units of pounds of SO_4 per SCC unit per percent of fuel sulfur. For example, if an eastern bituminous coal of 1.0 percent sulfur is being burned in a boiler, without an FGD, then the emission factor is 2.65 pounds SO_4 per ton of coal. Similarly, a residual fuel oil of 1.0 percent sulfur emits 5.30 pounds SO_4 per 1,000 gallons of oil consumed.

The sulfate emission rates vary by the type of coal (i.e., western versus eastern bituminous). In terms of percent of total sulfur emitted, the coal SO_4 emission factors (without FGD) are approximately 3.4 percent of total sulfur emitted for western bituminous and 7.0 percent for eastern bituminous. With FGD control, they range from about 1.2 percent to 2.0 percent. Residual fuel oil SO_4 emissions constitute about four percent of total sulfur emissions.

The SO_4 emission factors in Table 15 are based on data from stack tests at a limited number of boiler sites. In some cases, test data from only one boiler is the sole basis for specific factors listed in the table. A few assumptions have been made to supply the necessary factors for the ICE Model:

- Subbituminous coals are assumed to have the same sulfate emission factors as western bituminous coals
- Sulfate emission factors do not vary when using different particulate matter emissions control devices (i.e., fabric filter, ESP, side-stream separator, and multicyclone).

TABLE 15. INDUSTRIAL BOILER SULFATE EMISSION FACTORS
(Expressed as lbs SO_4/SCC unit/% sulfur fuel)

Fuel type	Without FGD	With FGD
Coal		
Eastern bituminous[a]	2.65	0.46
Western bituminous[b]	1.29	0.76
Subbituminous[b]	1.29	0.76
Residual fuel oil	5.30	2.62
Distillate fuel oil	5.65	--

[a] This factor, based on use of a multicyclone, is applied to all PM emissions control devices.

[b] This factor, based on use of an ESP, is applied to all PM emissions control devices.

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SECTION 4

FUEL CHOICE DECISIONS

This section summarizes the fuel choice decision criteria in the ICE Model. Given the industrial boiler characteristics reviewed in Section 3, cost estimates are generated and compared for each boiler in the population.

This section is organized in two parts. First, capital and annual non-fuel operating and maintenance (O&M) and fuel costs are discussed. Second, the fuel choice decision framework is described.

COST COMPONENTS

New Boilers

The major components of new industrial boiler capital costs are:

- Equipment (including freight)
  - boiler
  - auxiliary equipment such as instrumentation, pumps, fans, fuel handling, waste (flyash, bottom ash and sludge) disposal, water treatment, deaerator, condensate systems, economizers, coal feeders, coal bunkers, fuel oil storage tank, ash storage silo, pulverizers, stokers, crusher, clinker breaker, air heater, thawing equipment, compressed air system
  - pollution control
  - monitoring
- Direct installation
  - foundations and supports
  - ducts and stack
  - piping
  - enclosures and insulation
  - painting
  - electrical, lighting and ventilation
  - administrative facilities
- Indirect installation
  - engineering

  - construction fees
  - start-up and performance test
- Land and site development
- Other
  - interest during construction
  - contingencies
  - working capital.

Excluded are costs of research and development, lost production during installation and start-up, and steam and condensate piping beyond the boiler building.

The capital costs estimates are based on a greenfield boiler installation located in the Midwest.

The annual non-fuel O&M cost components are:

- Labor
- Materials, supplies, and spare parts
- Chemicals
- Utilities (i.e., electricity and water)
- Steam
- Solid waste disposal and water treatment requirements
- Overhead
- General and administrative costs, local property taxes, and insurance
- Interest on working capital
- Monitoring, reporting, and malfunction expenses.

The capital and annual non-fuel O&M cost estimates are generic. They do not vary with respect to special site-specific conditions. They are assumed to be representative of budget estimates used for planning purposes. It is also assumed that these costs will not increase in real terms over time or vary by region.

The capital and annual non-fuel O&M cost estimates for new industrial coal-fired boilers are unique for each coal type (the cost estimates are a

function of the heating value of the coal type) and type of combustion (underfeed stoker, spreader stoker, or pulverized coal). The capital and annual non-fuel O&M cost estimates for new oil/gas watertube boilers (excluding pollution control equipment) do not vary substantially by primary fuel type (natural gas or residual fuel oil) because these units are assumed to have dual-fuel firing capability.

The FGD system cost estimates are a function of:

- The boiler flue gas flow rate and fuel firing rate
- The sulfur content and heating value of the fuel type
- The required SO_2 emissions removal efficiency.

These costs estimates indicate that the scrubber costs have economies of scale related to the sulfur content of the fuel and the required SO_2 emissions removal efficiency. With respect to scrubber capital costs, however, EPA is assuming that the cost estimates used in the ICE Model should be based on high sulfur fuel types with 90 percent SO_2 emissions removal efficiency regardless of the sulfur content of the coal actually combusted.[1] This assumption reflects industry practice of designing FGD systems to provide maximum fuel firing flexibility. This flexibility is necessary since coal for industrial boilers is often bought from the spot market or under short-term contract. When lower sulfur coal is purchased, the scrubber may be operated at lower efficiency to conserve operating expenses. The scrubber O&M cost estimates in the ICE Model do reflect economies of scale associated with the sulfur content of the actual coal combusted and the actual operating efficiency. The minimum scrubber operating efficiency rate is 50 percent SO_2 emissions reduction. All of the boiler flue gas is scrubbed (regardless of the scrubber operating efficiency); it is not assumed that the boiler emission control system is designed to permit flue gas bypass of the scrubber.

The cost estimates for particulate matter emissions control equipment vary slightly by coal type. The type of control equipment used varies by the PM emissions regulation.

Boiler efficiency is improved with the use of low excess air (a NO_x emissions control technique) because less air is heated to flue gas tempera-

tures. This is reflected in the low excess air O&M cost estimates which are expressed as a negative expense (boiler fuel input savings).[2]

These boiler and pollution control equipment capital and O&M cost estimates have been developed by several EPA contractors. Cost estimates were developed for several model boilers. Cost algorithms were developed based on these generic point estimates. Radian Corporation (Research Triangle Park, North Carolina) is currently responsible for documenting and revising these cost algorithms for EPA's industrial boiler NSPS analysis.

Fuel Conversions of Existing Boilers

Scope--

Fuel conversions involve the retrofitting of equipment to allow the combustion of alternative fuels and usually entail shifting from an existing fuel to an alternate fuel. Since we are considering four fuel types, each boiler has three fuel conversion options; however, there are some restrictions on these options. We assume that no residual fuel oil boiler is likely to shift to distillate fuel oil since the fuel price differential between distillate and residual fuel oil should equal or exceed operating cost differentials. We further assume that no existing boiler is likely to shift from coal to oil or from coal to natural gas due to the lower operating expense of firing coal.

When considering a shift to coal, two cases are possible depending on whether or not the boiler originally was designed to burn coal. The conversion costs associated with each case can vary significantly. The two cases are described below.

- Coal-capable boilers: Coal-capable boilers are those units originally designed to burn coal which are currently burning oil or natural gas. The cost of converting coal-capable boilers back to coal depends on the operational status of equipment needed to burn coal. On one extreme, when the boiler already is using coal, conversion can be as simple as not burning any more oil or gas, and conversion costs are negligible. On the other hand, if auxiliary coal-burning equipment has not been installed, conversion can entail purchase of new equipment.

  Estimating the cost of such a fuel conversion can be accomplished only by determining the cost of components which may need to be purchased or replaced and the cost of boiler modifications. Modifi-

cation costs have been derived from costs reported by industrial users, equipment vendors, and consulting engineering studies. The cost of new equipment which may be necessary is estimated from basic equipment costs provided by vendors.

- Non-coal capable boilers: Non-coal capable boilers are units originally not designed to burn coal. Since attempts to convert to coal would involve major redesign of the furnace and possibly an efficiency loss, the cost of converting a non-coal capable boiler to burn coal is considered to be prohibitive.

An existing coal boiler also has fuel conversion options. When faced with a requirement to reduce SO_2 emissions (i.e., SIP modification or acid deposition control proposal), the boiler can switch to a lower sulfur content coal type (if other characteristics are similar, such as ash and Btu content, ash fusion temperature, lump size, grindability, volatility) or add an FGD system. If the sulfur content of the coal type changes considerably (i.e., a one percent change as from two percent to one percent sulfur) and an ESP is currently in place to control PM emissions, ESP performance and efficiency are generally reduced and it is necessary to upgrade the ESP.

Cost Estimating Procedures--

For each fuel conversion option, EEA examined the effect of fuel switching on the important components of the boiler: burner/stoker, heat exchanger tubes, refractories, sootblowers, economizers, air blowers, and the fuel control system (valves, metering devices, return flow equipment). The extent of change required for each of the possible fuel conversion cases was estimated. The installed cost of the new components considered necessary was estimated from costs provided by vendors.

Every fuel conversion requires burners to be replaced or stokers to be installed (if dual-fuel firing capability is not already in place). Heat exchanging tubes need to be replaced if the boiler is converted to burn residual oil or coal. These tubes prevent ash accumulation on the ribbed tubes and increase the surface area exposed to combustion products. The amount of refractory brick replaced depends on the type of fuel the boiler is retrofitted for. The change is nominal when the boiler is converted to burn gas, distillate oil, or residual oil. However, converting to coal requires extensive refractory change to prevent eutectic formations and significant deterioration

of the refractory. A change to residual fuel oil and coal requires installation of high-quality refractory.

Accumulated ash can reduce significantly heat transfer through tubes; ash deposition can be severe when burning residual fuel oil and coal. Therefore, sootblowers (devices that use steam/air to dislodge ash accumulation) are installed when boilers are converted to these two fuels. Typically, residual fuel oil and coal require greater percentages of excess air for complete combustion. Therefore, additional air blower capacities also are installed for these fuels.

When considering the above fuel conversions, no site-specific data on retrofit requirements were examined. We could, therefore, be under- or over-estimating conversion costs. This variance may be especially pronounced when switching to coal in a coal-capable boiler. We also assume that boiler efficiency remains unaffected by fuel conversion. For some boilers, this probably will not be the case. When switching to residual fuel oil from natural gas, there is a fundamental change in heat transfer mechanisms. The combustion of residual fuel oil produces luminous flames which increase the radiation heat transfer in the radiation section of the boiler. The flue gases passing through the convection section and the superheating section of the boiler are, therefore, at a lower temperature. This lower flue gas temperature may pose a problem in some boilers, where the steam is superheated to high temperatures and pressures in the convection zone. A rearrangement, by installing superheating tubes in the radiation section, may be necessary.

Table 16 details the eight fuel conversion options for boiler sizes 29-73 MW (100-250 MMBtu/hr). For a particular conversion, the blanks in the boiler-related direct costs suggest that no change was considered necessary. Conversion from residual fuel oil to distillate fuel oil is not considered likely. Therefore, conversion costs for this option were not estimated. The total fuel conversion capital cost estimates are summarized in Table 17.

It is generally more expensive to install or modify pollution control equipment at an existing facility than at a new plant for a variety of reasons.

TABLE 16. BOILER FUEL CONVERSION CAPITAL COSTS BY COMPONENT[a]

Cost component	G to D	G to R	G to C	D to R	D to C	R to C	D to G	R to G
Burners/stokers	33,594	36,637	503,751	36,637	503,751	503,751	30,552	30,552
Heat exchanger tubes	--	216,342	216,342	215,342	216,342	--	--	--
Refractory material	959	1,571	81,301	1,571	81,301	81,301	959	959
Sootblowers	--	58,482	58,482	58,482	58,482	--	--	--
Air blowers	--	17,942	17,942	17,942	17,942	--	--	--
Total	34,553	330,974	877,818	330,974	877,818	585,052	31,511	31,511

[a] Boiler size 29-73 (100-250 MMBtu/hr). These costs do not include indirect costs, fuel handling, ash handling, and pollution control systems. G - Natural gas. R - Residual fuel oil. D - Distillate fuel oil. C - Coal capable boiler. Source: Energy and Environmental Analysis, Inc.

TABLE 17. BOILER FUEL CONVERSION CAPITAL COSTS[a]
($1978)

Boiler size class MMBtu/hr (MW)	Retrofit from	Retrofit to: Natural gas	Distillate oil	Residual oil	Coal[b]
>250 (>73)	Natural gas	--	62,626	592,273	1,432,113
	Dist. oil	57,335	--	592,273	1,432,113
	Resid. oil	57,335	--	--	909,056
100-250 (29-73)[c]	Natural gas	--	34,553	330,974	877,818
	Dist. oil	31,511	--	330,974	877,818
	Resid. oil	31,511	--	--	585,052
<100 (<29)	Natural gas	--	17,825	127,337	363,806
	Dist. oil	16,247	--	127,337	363,806
	Resid. oil	16,247	--	--	247,812

a These costs do not include indirect costs, fuel handling, ash handling, and pollution control systems. They do include burners/stokers, heat exchanger tubes, refractory material, sootblowers, and air blowers. Source: Energy and Environmental Analysis, Inc.

b Coal-capable boilers.

c Shown by component in Table 16.

Some of the more significant cost factors which increase the cost of a retrofit are:

- Whether the equipment can be installed as a package or must be field erected
- The topography and nature of the site
- Availability of necessary utilities such as water or electricity
- The space available for the equipment and the proximity of this space to the boiler.

These factors can significantly affect the total cost of retrofitting pollution control equipment to an existing plant. For example, Table 18 shows the normal cost factors which are applied to the delivered but unerected cost of pollution control equipment. Table 19 shows the expected range of adjustments to these factors which have been reported in cases involving retrofits.

Before explaining what causes variations from a new plant case, it should be noted that not all factors are necessarily higher in retrofit cases. For example, in most instances, the within battery limits cost of piping, painting, insulation, and electrical work is not significantly different between new and retrofit cases since these factors are related to the size of the equipment and not whether it is applied at a new or existing plant. In some cases, site preparation cost can actually be less at an existing plant since the land may be available, cleared, and ready for installation. For most of the other cost factors, the cost of retrofit will greatly exceed the cost at a new plant. Cost increases can be expected in:

- Erection: In many retrofit situations, space is constrained, and additional labor cost is incurred. Higher costs are also caused by long duct runs and the potential need to remove or relocate existing structures.
- Additional facilities and buildings: At existing plants, maintenance facilities and control areas may not be adequate and additional facilities may have to be added. For a new facility, the additional cost to expand control rooms etc. can be accomplished at minimum cost.
- Engineering: Additional time and effort is needed to design equipment which is both compatible with existing processes and which will fit into the existing space.

TABLE 18. TYPICAL COST FACTORS

Cost area	Factor[a]
Direct costs (Purchased equipment)[b]	1.00
Installation costs	
Foundations	0.04
Erection	0.50
Electrical	0.08
Piping, painting, insulation	0.10
Subtotal	0.72
Indirect costs	
Engineering	0.10
Field expenses	0.20
Construction fee	0.10
Contingency	0.10
Subtotal	0.50
Total	2.22

[a] Multiply by purchased equipment costs.

[b] Includes cost of equipment plus taxes, freight, and instrumentation.

TABLE 19. RANGE OF ADJUSTMENTS FOR RETROFIT

Cost area	Factor range[a]
Direct costs	1.00 - 1.05
(Purchased equipment)	
Installation costs	
Foundation	0.04
Erection	0.45 - 1.00
Electrical	0.08
Pipe, paint, insulation	0.10 - 0.12
Site preparation	0.00 - 1.00
Subtotal	0.67 - 2.24
Indirect costs	
Engineering	0.10 - 0.30
Field expenses	0.15 - 0.30
Construction fee	0.10 - 0.15
Contingency	0.10 - 0.30
Subtotal	0.45 - 1.05
Total	2.12 - 4.34

[a] Multiply by purchased equipment costs.

- Contingencies: In any capital budget money is set aside to account for unexpected problems. In a retrofit situation the amount of this fund is generally increased.

All pollution control retrofit costs factors in the ICE Model are expressed as percentage increases in total costs over a "typical" new plant. "Typical" new plant costs are defined as those associated with EPA's current industrial boiler NSPS analysis.[2] The cost factors reflect cost increases over levels which would be incurred by a specified percent of boilers that vendors had worked on. For example, what increase in cost would be incurred by the lowest ten percent for all retrofit situations, by the highest ten percent, etc. Because relatively few FGD systems or baghouses have been added to existing plants, all cases of adding new equipment to an existing plant, regardless of the type of device, are considered to have the same cost distribution.

The vendors contacted in this review (all of whom requested confidentiality) represent firms responsible for a large percentage of the industrial air pollution market. It is felt that their opinions represent a reasonable estimate of the overall distribution of cost increases.

Tables 20 and 21 show the results of this study. Factors shown are based on cost increases over typical new plant construction costs. As can be seen on Table 20, for a small proportion of plants, adding a new control device will cause no problems because adequate space is available and there are no other difficulties in the installation. Also, for a small group of plants it may be necessary to relocate process equipment to install new FGD. This is caused by a total lack of space and no possibility of acquiring new space. However, for all but the largest industrial boilers where it is economical to use sodium once-through FGD units, the space requirements for these systems is small. The ICE Model does assume that the plant does not choose or is not required to remove existing production facilities to make space for pollution control equipment for five percent of the population (Table 20).

Table 21 shows the expected cost to upgrade existing ESP's to meet existing particulate matter emission regulations when the sulfur content of the coal changes considerably. For purposes of this study, a substantial change in

TABLE 20. ADDITIONAL CAPITAL COST OF RETROFITTING NEW FGD CONTROL DEVICE TO EXISTING PLANTS

Percent of population	Percentage increase in capital cost[a]
5	0
60	15 - 25
20	25 - 30
10	30 - 40
5	Cannot retrofit[b]

[a] Over and above cost estimates for a new FGD for a new industrial boiler.

[b] Retrofit cannot be carried out without removal of production equipment.

TABLE 21. INCREASED CAPITAL COSTS
TO UPGRADE AN ESP

Percent of population	Percentage of capital cost of a new ESP
5	15
60	5 - 25
25	30 - 40
10	Add new control device

coal sulfur content is defined as: 1) a one percent change in sulfur content, 2) a sulfur content that drops below one percent, and 3) the selection of a subbituminous coal as fuel. ESP upgrade is a combination of flue gas conditioning and the addition of precipitation sections.

Fuel Costs

The ICE Model includes the following fuel types:

- Natural gas
- Distillate fuel oil
- Residual fuel oil
  - 3.0 percent sulfur
  - 1.6 percent sulfur
  - 0.8 percent sulfur
  - 0.3 percent sulfur
- Coal (up to 11 types -- defined by the model user).

Projected fuel prices are expected to vary by Federal region (but not to vary within a Federal region).* Projected industrial fuel prices are exogenous parameters. They are required by Federal region for 1980-2040 (every fifth year) in 1980 ¢/MMBtu.

INVESTMENT DECISION APPROACH

Decision Criteria for New Industrial Boilers

The fuel choice decision framework in simulation models is usually based on the premise that industry will try to minimize the total costs of generating steam or heat over the useful life of the facility. Specifically, decision makers will tend to select that fuel with the lowest expected life cycle costs.

This approach does not take into account other less quantifiable economic factors which also may affect the fuel choice decision. Examples of other factors include:

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* Intra-regional variability is simulated in the ICE Model by assigning SIP's at the AQCR level (not using regional "average" SIP's).

- Site-specific conditions (e.g., variable costs of capital among firms and costs for development of coal storage facilities such as silos in space limited sites)
- Previous experience with burning coal (e.g., a boiler house, rail siding or coal yard, and other coal handling equipment may already be on-site)
- Perception of fuel supply reliability and price stability (i.e., coal is less likely to experience supply disruption than oil or gas fuels).

EPA decided that the least-cost approach should be modified based on an empirical analysis of recent industrial boiler sales data. The fuel choice decision criteria should not only be a function of readily quantifiable expected differences in life cycle costs, but also an empirical function of less quantifiable expected cost differences and intangible factors.

Data on new industrial boiler sales were evaluated. This data base included over 400 orders for new industrial coal, oil, and gas boilers between 1977 and 1983. The probability of selecting coal was estimated, using this data base, as a function of boiler size, previous coal experience, region and expected cost differences.

For a given set of projected fuel prices and government policies (energy, environmental, and tax), the ICE Model calculates total after-tax net present values (NPV) by fuel type for each new industrial boiler record and selects the primary fuel type as follows:

1) Estimate the boiler capital and annual non-fuel O&M costs for each fuel type (fuel oil, natural gas, and coal).
2) Estimate the capital and annual non-fuel O&M costs for applicable pollution control equipment options for each fuel type.
3) For each combination of fuel type and alternative pollution control equipment configuration,* the after-tax NPV of total boiler and pollution control equipment capital and annual non-fuel O&M costs is calculated.
4) The after-tax NPV of projected fuel costs is derived and added to the total after-tax NPV of the boiler and pollution control equip-

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* For example, three FGD systems or several particulate matter emissions control equipment alternatives for new industrial coal-fired boilers.

ment capital and annual non-fuel O&M costs for each fuel type/pollution control equipment configuration.

5) The total after-tax NPV is compared for each fuel type/pollution control equipment configuration; the oil/gas alternative and the coal alternative with the lowest total after-tax NPV costs are selected.

6) The cost difference (least-cost oil/gas total after-tax NPV less least-cost coal total after-tax NPV)* is calculated.

7) An assumption is made whether or not this new industrial boiler will be located at a plant with previous coal burning experience.

8) The probability of selecting coal is estimated based on the boiler size class, expected total after-tax NPV cost difference and previous coal experience assumption.

9) A random variable is generated and compared with the estimated probability of selecting coal. If the random variable is less than the probability estimate, the fuel type selected is coal. If the random variable is larger than the probability estimate, the fuel type selected is fuel oil or natural gas (the alternative with the lowest total expected after-tax cost).

Life cycle costs are compared in the ICE Model on an after-tax basis because Federal tax laws were different for industrial oil/gas boilers than they were for industrial coal units. The Energy Tax Act of 1978 (Title III) provided tax incentives for the use of coal and alternative fuels. New industrial coal-fired boiler investments qualified for the regular ten percent investment tax credit (ITC) and accelerated depreciation methods. However, investments in new industrial oil- and gas-fired boilers did not qualify for the regular ITC and straight line depreciation was required for these units.

Overview of NPV Calculations--

A conventional NPV approach is used to calculate the total after-tax cost of producing steam or hot water in a boiler. The components of this calculation include:

FC_t - the fuel cost in year t

OM_t - the annual non-fuel operating costs in year t

C - the total capital cost of the facility

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* Including capital, O&M, and fuel cost estimates for the boiler and pollution control equipment.

C_t - the capital cost expended in year t

D_t - depreciation expense in year t

e - the share of capital cost which can be expensed (does not form the basis for capital depreciation)

T - the marginal income tax rate (e.g., 0.34)

ITC - the allowable investment tax credit (e.g., 0.1 or 0.0)

i - the real, after-tax discount rate (e.g., 0.08)

L - the investment period (years)

$$\text{After-tax NPV} = \sum_{t=1}^{L} \frac{(1-T)(-FC_t-OM_t-D_t-eC) + D_t-(1-e)C_t + (1-e)(C_t)(ITC)}{(1+i)^{t-1}}$$

Expensible Construction Costs-- A portion (ten percent) of equipment and facility construction costs is considered expensible in the ICE Model. These expensible costs, allowable deductions for income tax purposes, are excluded from the depreciable capital cost. Expensible costs normally are higher than initial engineering costs. They can vary for each case depending on the amount of work done in-house and the portion of turnkey costs (i.e., total package delivered to the fuel user). The estimate that ten percent of construction costs are expensible is assumed to be typical, based on discussions with equipment vendors. It is also assumed to be expensed in the first year.

Construction Period-- This period refers to the interval when capital expenditures are being incurred for facility construction, and no fuel is being burned. This period is assumed to be two years. $D_t=FC_t=OM_t=0$, for t=1,2. $C_t=0$, for t>2.

Depreciation-- Depreciation is an accounting convention which represents the decline in property value as a result of time and/or use. This is important in the calculation of income tax liabilities. Industrial boilers are depreciable property. In this analysis, the annual depreciation charges must be converted from nominal to real dollars.[3]

The Tax Reform Act of 1986 modified the ACRS and changed the method of depreciation for property placed in service in 1987 and later. The class life

of industrial steam generating systems is 22 years and, therefore, they are reclassified as 15-year recovery property. The 150 percent declining balance depreciation method is specified and the half-life convention is required.

Investment Tax Credit (ITC)-- The Tax Reform Act of 1986 repealed the ITC for property placed in service beginning January 1, 1986.

Income Tax Rate-- The Tax Reform Act of 1986 established four business Federal income tax rates. The tax rate which is applicable to businesses with the largest net incomes is 34 percent and this value is used in the ICE Model.

Discount Rate-- A discount rate is the expression of the time value of capital used in equivalence calculations comparing alternatives. This rate is essentially a value judgement based on a compromise between present consumption (i.e., distribution of profits to stockholders) and capital formation. The discount rate represents the required rate of return; that rate at which stockholders are indifferent between this and their next best investment opportunity. Traditionally, the required rate of return simply has meant the cost of capital. If an investment does not pay for itself plus the charges incurred to finance the project, a firm is better off not making the investment.

The discount rate in the ICE Model represents the average real (not nominal) after-tax cost of capital. The discount rate for new boiler investment calculations in the ICE Model is eight percent.

Investment Period-- The investment period is the number of years of cash flows included in the calculation of the after-tax NPV. The length of the investment period is important in that it affects the relative economics of capital-intensive alternatives such as coal. If the investment period is short (e.g., five years), the fuel savings associated with coal may not be sufficient to offset the high coal capital and annual non-fuel O&M costs and oil or gas would be selected as the least-cost fuel type. If a long period is used (e.g., 40 years), the coal fuel cost savings may be sufficient in many cases to offset the high coal capital and annual non-fuel O&M costs.

The current investment period in the ICE Model is 15 years. This includes the two-year construction period and 13 years of operation. Estimates of the

physical life of new industrial boilers range from 20 years for package units to 45 years for large field erected units.[4] Due to the discounted cash flow decision criteria, annual O&M and fuel expenses contribute relatively little to the total NPV for periods longer than 15 years. Therefore, a single investment period for all new industrial boiler fuel choice decisions is not expected to seriously bias the analysis.

Calculation of NPV Factors-- Table 22 summarizes the financial parameter assumptions in light of the Tax Reform Act of 1986. Tables 23 and 24 summarize the development of after-tax NPV factors. Table 23 shows that the after-tax NPV is 76.26 cents for every dollar of boiler and pollution control equipment capital costs.

Table 24 indicates that the after-tax NPV is $4.83 for every dollar of annual non-fuel O&M costs. This is based on the assumption that the annual non-fuel O&M costs do not increase in real terms over time. Table 25 presents a similar calculation for fuel costs. In this example, the after-tax NPV for fuel costs is $21.66/MMBtu x the boiler annual natural gas consumption quantity.

The total after-tax NPV equals the sum of:

- Total capital cost* x 0.7626
- Total annual non-fuel O&M cost* x 4.83
- Total after-tax NPV of fuel costs (e.g., annual natural gas consumption x $21.66/MMBtu from Table 25).

Estimates of the Probability of Selecting Coal in New Industrial Boilers-- A set of simple relationships was derived relating the probability of installing coal-fired capability to boiler size, region, costs, and previous experience with coal. This is not applicable to sizes less than 9 MW (30 MMBtu/hr) because the data base did not include any very small units and the cost algorithms are not well defined for this category.

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* Boiler and pollution control equipment.

TABLE 22. FINANCIAL PARAMETER ASSUMPTIONS FOR NEW INDUSTRIAL BOILER DISCOUNTED AFTER-TAX NPV COST COMPARISONS

Financial Parameter	Value
Investment period (years)	15
Depreciation method	150% declining balance[a]
Depreciation period (years)	15[b]
Investment tax credit (percent)	0
Income tax rate (percent)	34
After-tax, real discount rate (percent)	8
Inflation rate (percent)[c]	5
Construction period (years)[d]	2

[a] With a change to straight line depreciation in the seventh year.

[b] Applicable to property with a class life of 20-24 years. The half-life convention is required.

[c] Used to convert depreciation deductions from nominal to real terms.

[d] Part of the investment period.

TABLE 23. DERIVATION OF THE AFTER-TAX NPV FACTOR FOR CAPITAL EXPENSES[a]

Year	Depreciation: Nominal before-tax[b]	Depreciation: Real after-tax[c]	Expensible construction[d]	Depreciable capital investment[e]	Annual cash flow[f]	Discounted cash flow[g]
1			0.066	0.4500	0.4566	0.4566
2				0.4500	0.4500	0.4167
3	0.0450	(0.0139)			(0.0139)	(0.0119)
4	0.0855	(0.0251)			(0.0251)	(0.0199)
5	0.0770	(0.0215)			(0.0215)	(0.0158)
6	0.0693	(0.0185)			(0.0185)	(0.0126)
7	0.0623	(0.0158)			(0.0158)	(0.0100)
8	0.0561	(0.0136)			(0.0136)	(0.0079)
9	0.0531	(0.0122)			(0.0122)	(0.0066)
10	0.0531	(0.0116)			(0.0116)	(0.0058)
11	0.0531	(0.0111)			(0.0111)	(0.0051)
12	0.0531	(0.0105)			(0.0105)	(0.0045)
13	0.0531	(0.0101)			(0.0101)	(0.0040)
14	0.0531	(0.0096)			(0.0096)	(0.0035)
15	0.0531	(0.0091)			(0.0091)	(0.0031)
						0.7626

[a] Total capital cost is 1.0.

[b] Only 90% of the capital cost is assumed to be depreciable; half-year convention for first year of depreciation.

[c] Real depreciation = nominal depreciation/$(1.05)^{t-1}$;
(real depreciation * [1 - tax rate]) less real depreciation, or -0.34 * real depreciation; -0.34 * nominal depreciation/$(1.05)^{t-1}$

[d] (1 - tax rate) * 10% of the total capital cost, or 0.66*0.1*1.0 = 0.066

[e] Total capital costs less expensible construction costs allocated evenly over the two-year construction period, or (1.0 - [0.1*1.0])/2 = 0.45

[f] Real after-tax depreciation deduction + expensible construction + depreciable capital investment.

[g] Annual cash $flow_t/(1.08)^{t-1}$

TABLE 24. DERIVATION OF THE AFTER-TAX NPV FACTOR FOR ANNUAL NON-FUEL O&M COSTS[a]

Year	Annual Cash Flow	Discounted Cash Flow[b]
1	0.0	0.0
2	0.0	0.0
3	0.66[c]	0.566
4	0.66	0.524
5	0.66	0.485
6	0.66	0.449
7	0.66	0.416
8	0.66	0.385
9	0.66	0.357
10	0.66	0.330
11	0.66	0.306
12	0.66	0.283
13	0.66	0.262
14	0.66	0.243
15	0.66	0.225
		4.830

[a] Annual non-fuel O&M costs = 0.0 for years 1 and 2 (construction period)
= 1.0 for years 3-15

[b] Annual cash $flow_t/(1.08)^{t-1}$

[c] (1 - tax rate) * annual non-fuel O&M cost = 0.66 * 1.0

TABLE 25. EXAMPLE CALCULATION OF THE AFTER-TAX NPV OF ANNUAL FUEL EXPENSES

Year	After-tax discounted cash flow factor[c]	Natural gas price[a] ($/MMBtu)	After-tax NPV[b] ($/MMBtu)
1[d]	0.000[d]	3.59	0.00
2[d]	0.000[d]	3.76	0.00
3	0.566	3.94	2.23
4	0.524	4.06	2.13
5	0.485	4.19	2.03
6	0.449	4.32	1.94
7	0.416	4.45	1.85
8	0.385	4.59	1.77
9	0.357	4.66	1.66
10	0.330	4.72	1.56
11	0.306	4.78	1.46
12	0.283	4.86	1.38
13	0.262	4.93	1.29
14	0.243	5.00	1.22
15	0.225	5.07	1.14
			21.66

[a] Presented for illustrative purposes. Not a current fuel price projection in the ICE Model.

[b] After-tax discounted cash flow factor x fuel price.

[c] See Table 24.

[d] Construction period. Boiler is placed in service at the beginning of year 3.

The statistical model:

- Reflects a strong response in the predicted coal market share to changes in cost (e.g., resulting from alternative fuel price forecasts or alternative air emissions regulations) and
- Incorporates a regional effect

Table 26 summarizes the revised statistical fuel choice decision algorithm. Figures 5-7 illustrate the predicted coal market shares as functions boiler size, annual capacity utilization rate, previous coal experience (yes or no), region, and expected cost differences.*

Accounting for Coal Experience-- There are two steps in the model related to accounting for coal experience. First, each new boiler created in the model has to be "located" in a plant with or without coal experience. Second, the model has to be able to track the population of boilers over time according to presence/absence of coal experience. This latter point is necessary since the share of boilers in plants with coal experience will vary over time as a function of new boiler decisions and retirement assumptions.

Levels of coal experience are estimated by Federal region and boiler size. Obviously, we will not know exactly where new boilers will be located in the future. Hence, in the initial forecast year, the experience factor (e.g., probability of being located in a plant which has coal experience) is based on recent, but historical, data.

About 70 percent of industrial coal use is concentrated in only three regions of the country: Middle Atlantic (Federal region 3), South Atlantic (Federal region 4), and the Midwest (Federal region 5). Using EPA's NEDS inventory of boiler data organized by plant, roughly 17 percent of the plants in the above three regions had coal experience. For the other regions, only two percent of the plants had coal experience. Relying on the same boiler survey data used to derive the decision algorithms, the prevalence of experience was further distinguished by boiler size for the two larger size

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* Total oil/gas after-tax NPV less total coal after-tax NPV; capital, O&M and fuel for boiler and pollution control equipment.

TABLE 26. STATISTICAL FUEL CHOICE
DECISION ALGORITHM FOR NEW INDUSTRIAL BOILERS[a]

Probability of choosing coal = 1/[1 + exp (-L(X))]

L(X) = -2.5426 + (DMED * 0.3664) + (DLARGE * 2.0473) + (SEXP * 1.1216) + (MEXP * 3.3945) + (LEXP * 3.9668) + (ABSDOL * 0.2903) + (D45NOEXP * 0.008846)

DMED = 1, if the boiler size is between 100 and 250 MMBtu/hr
= 0, otherwise

DLARGE = 1, if the boiler size is larger than 250 MMBtu/hr
= 0, otherwise

SEXP = 1, if the boiler size is smaller than 100 MMBtu/hr and if the plant is expected to have previous coal experience
= 0, otherwise

MEXP = 1, if the boiler size is between 100 and 250 MMBtu/hr and if the plant is expected to have previous coal experience
= 0, otherwise

LEXP = 1, if the boiler is larger than 250 MMBtu/hr and if the plant is expected to have previous coal experience
= 0, otherwise

ABSDOL = the difference (oil/gas minus coal) in the total (capital, O&M and fuel; boiler and pollution control equipment) after-tax NPV in millions of 1978 dollars

D45NOEXP = the product of the boiler size (MMBtu/hr) and the annual capacity utilization rate (fraction), if the boiler is located in Federal regions 4 (South Atlantic) or 5 (Midwest) and if the plant is not expected to have previous coal experience
= 0, otherwise

[a]Energy and Environmental Analysis, Inc.

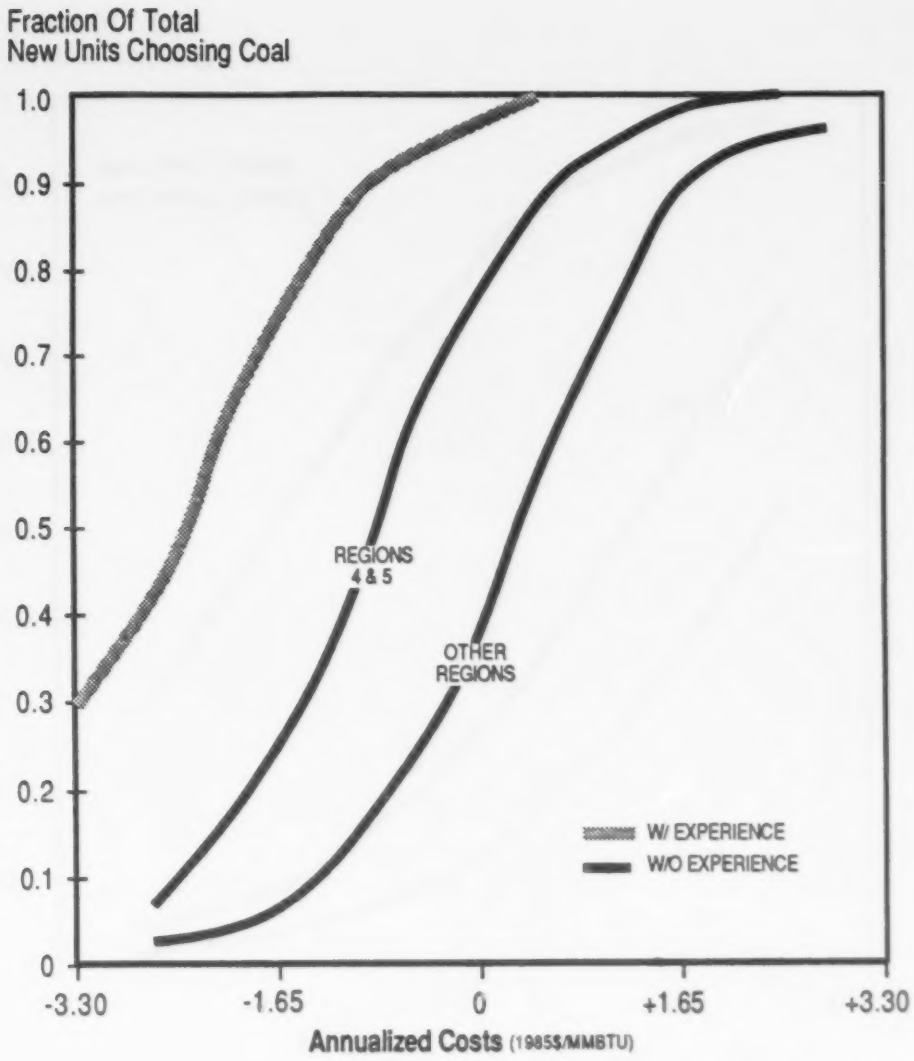

Figure 5. Coal market share in small (e.g., 350 MMBtu/hr, 55 percent capacity utilization rate) boilers versus total cost differences.

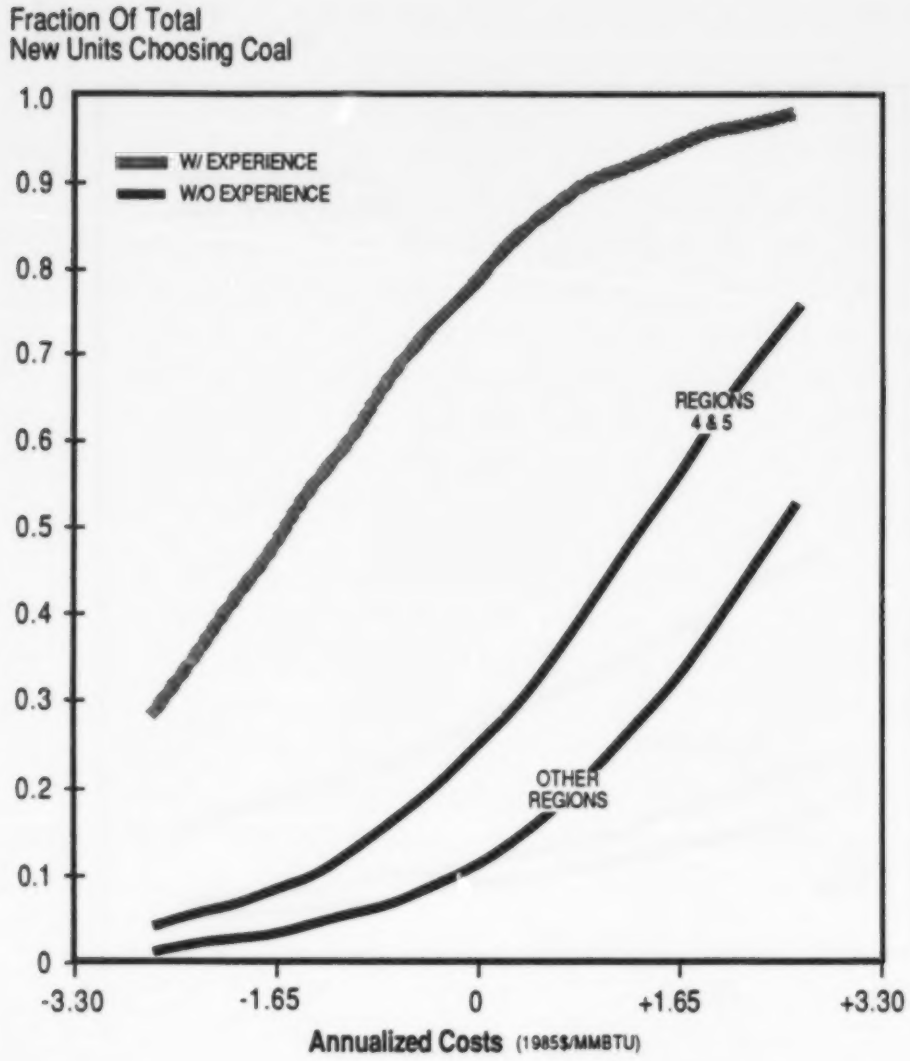

Figure 6. Coal market share in medium (e.g., 200 MMBtu/hr, 55 percent capacity utilization rate) boilers versus total cost differences.

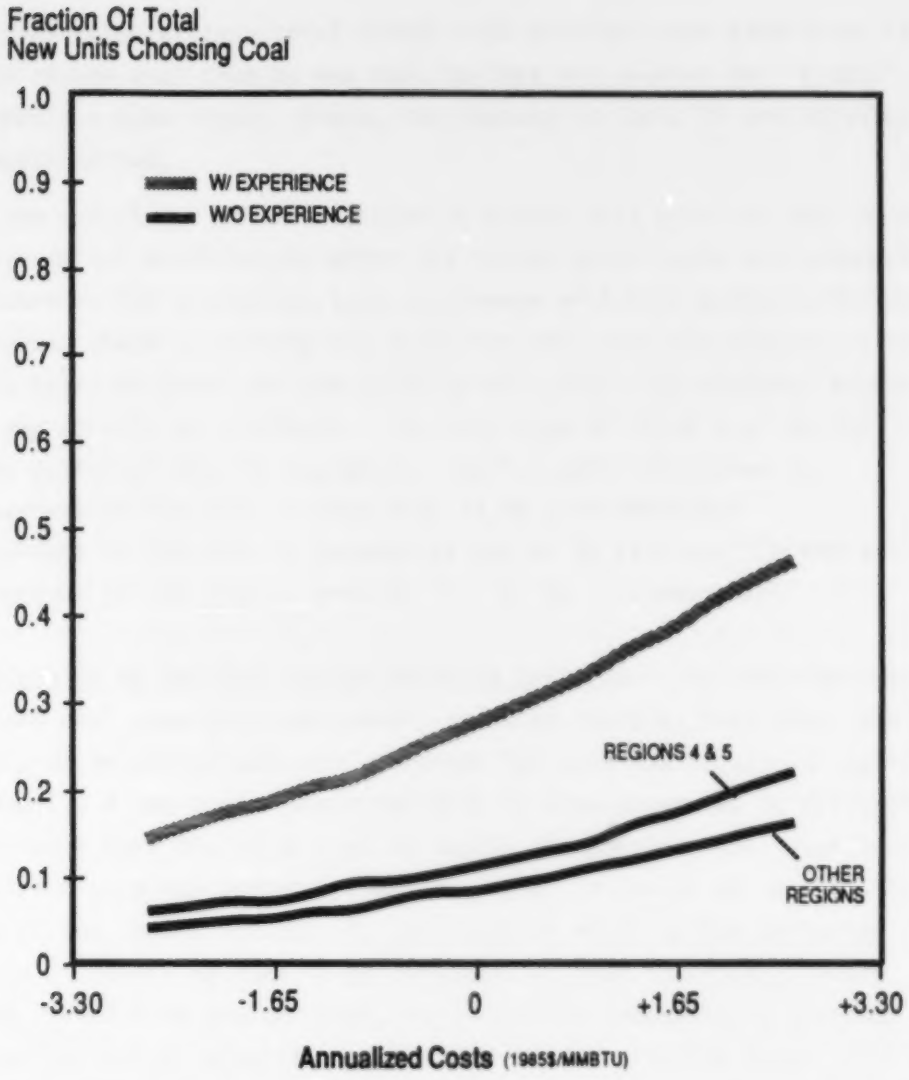

Figure 7. Coal market share in small (e.g., 75 MMBtu/hr, 55 percent capacity utilization rate) boilers versus total cost differences.

classes. Using this approach, the initial probabilities of the presence of coal experience are shown in Table 27.

The proportion of industrial plants with previous coal experience is allowed to change over time as new coal boilers are ordered for "plants" without previous experience. Hence, the factors in Table 27 are adjusted in each forecast period.

For new industrial boilers located at plants with previous coal experience, coal and ash handling equipment and installation costs are subtracted. This is based on the assumption that experience with coal probably reflects many decisions where relatively low costs for coal were anticipated or were previously realized (coal and ash handling equipment with adequate excess capacity may already be in place). The magnitude of these coal boiler (excluding pollution control equipment) capital cost reductions is:

- 18 percent if the size is less than 29 MW (100 MMBtu/hr)
- 15 percent if the size is between 29 and 51 MW (100 and 175 MMBtu/hr)
- 12 percent if the size is greater than 51 MW (175 MMBtu/hr)

Application of the Fuel Choice Decision Criteria-- As described above, the previous coal experience parameter, expected costs by fuel type, and the probability of selecting coal are estimated for each new industrial boiler in the ICE Model. A two-digit random variable is also generated (a different random variable than the value used to assign the previous coal experience parameter) for each new industrial boiler. Coal is chosen as the fuel type if the value of the random variable is less than or equal to the estimated probability of selecting coal (a percentage) for that individual record. If the random variable is greater than this estimated probability, residual or distillate fuel oil or natural gas (the alternative with the lower total after-tax NPV) is selected.

For example, assume that a new industrial boiler is larger than 73 MW (250 MMBtu/hr), without previous coal experience in Federal region 5 (Midwest) and the annualized cost difference (oil/gas minus coal) is estimated to be $0.85/MMBtu (1985 dollars). From Figure 5, the estimated probability of selecting coal is 50 percent. Coal is selected as the fuel type for this new

TABLE 27. INITIAL PROBABILITY OF THE PRESENCE OF PREVIOUS COAL EXPERIENCE

	Boiler Size, MW (MMBtu/hr)		
Federal regions	Less than 29 (100)	29-73 (100-250)	Greater than 73 (250)
3, 4, and 5	17%	50%	75%
Other	2%	25%	25%

unit if the two-digit random variable is less than or equal to "50". Residual fuel oil, distillate fuel oil, or natural gas (whichever alternative has the smallest total after-tax NPV, including all capital, O&M, and fuel expenses) is selected if this two-digit random variable is larger than "50".

Decision Criteria for Existing Industrial Boilers

The decision criteria for retrofitting fuel types and/or pollution control equipment in existing industrial boilers is based on a straightforward comparison of total (capital, O&M, and fuel) after-tax NPV's for each alternative (e.g., continuing to burn medium sulfur residual fuel oil or switching to natural gas). The discount rate (the real, not nominal, after-tax cost of capital) used in the ICE Model for existing boiler investment calculations is 12 percent.* Fifteen years of cash flows are considered for new boiler cost comparisons. However, only seven years of cash flows are considered for existing boiler cost comparisons. If the alternative involves changing fuel types, the shorter time horizon insures that the retrofit occurs when it is economical to do so (and not prematurely). For every dollar of boiler and pollution control equipment capital costs, the after-tax NPV is 79.72 cents. The after-tax NPV is $3.373 for every dollar of annual non-fuel O&M costs. These after-tax NPV factors were developed based on the assumption that there would not be a significant construction period.

If the alternative involves upgrading an ESP, another random variable is generated to estimate this capital cost (from Table 21). This upgrade may cost from 15 to 100 percent of the capital cost of a new ESP. If the alternative involves adding a scrubber, the scrubber may cost as much as 35 percent higher than the capital cost estimate for a new FGD system or the scrubber retrofit may be infeasible (see Table 20), depending upon the value of another random variable. Table 28 shows how the capital cost factor is estimated.

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* By comparison, 8 percent is used for new unit fuel choice decisions.

TABLE 28. CAPITAL COST FACTORS

Random variable	New FGD at an existing plant[a]	ESP upgrade[b]
≤4	1.000	0.15
5-64	1.200	0.20
65-84	1.275	0.35
85-89	1.350	0.35
95-99	Cannot retrofit	1.00

[a] Derived from Table 20.

[b] Derived from Table 21.

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2. Ibid. p. A-15.

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3. Note the cost calculation methodology proposed by the Economic Regulatory Administration, U.S. Department of Energy to be used to compare the costs of burning alternate fuels in new industrial boilers related to the Powerplant and Industrial Fuel Use Act (45 FR 84967, December 24, 1980).

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APPENDIX A

INDUSTRIAL COAL CHARACTERISTICS CURRENTLY USED IN EPA'S INDUSTRIAL BOILER NSPS ANALYSIS

TABLE A-1. SULFUR DIOXIDE EMISSION RATES BY COAL TYPE*

Coal type	Range		Average	
	ng/J	(lb/MMBtu)	ng/J	(lb/MMBtu)
Bituminous	<464	(<1.08)	408	(0.95)
	464-718	(1.08-1.67)	593	(1.38)
	718-1,075	(1.67-2.50)	894	(2.08)
	1,075-1,432	(2.50-3.33)	1,225	(2.85)
	1,432-2,150	(3.33-5.00)	1,784	(4.15)
	>2,150	(>5.00)	2,382	(5.54)
Subbituminous	<464	(<1.08)	408	(0.95)
	464-718	(1.08-1.67)	593	(1.38)
	718-1,075	(1.67-2.50)	894	(2.08)

* Annual average (not 30-day, rolling average) values. Memorandum from K. Schweers and C. Ebert (ICF, Inc.) to J. Greenwald (EPA). Industrial Coal Prices for NSPS Analyses by Federal Regions. April 22, 1983.

TABLE A-2. AVERAGE ASH CONTENT BY REGION
(BITUMINOUS COAL TYPES)*
(percentage, moist)

Federal region	ng SO_2/J (lb SO_2/MMBtu)					
	<464 (<1.08)	464-718 (1.08-1.67)	718-1,075 (1.67-2.50)	1,075-1,432 (2.50-3.33)	1,432-2,150 (3.33-5.00)	>2,150 (>5.00)
1. New England	11.9	11.9	13.0	13.0	13.0	13.0
2. New York/New Jersey	11.9	11.9	11.4	13.0	13.0	13.0
3. Middle Atlantic	11.8	12.4	12.6	12.2	13.0	13.0
4. South Atlantic	11.7	12.3	12.3	11.9	11.9	11.8
5. Midwest	11.0	11.0	10.5	10.9	12.2	12.0
6. Southwest	12.1	11.8	15.0	11.8	12.2	12.3
7. Central	10.0	12.4	12.4	11.1	11.1	11.1
8. North Central	10.0	10.0	10.0	--	--	--
9. West	11.3	11.3	16.3	--	--	--
10. Northwest	10.0	10.0	10.0	--	--	--

* Memorandum from K. Schweers and C. Ebert (ICF, Inc.) to J. Greenwald (EPA). Industrial Coal Prices for NSPS Analyses by Federal Regions. April 22, 1983.

TABLE A-3. AVERAGE ASH CONTENT BY REGION
(SUBBITUMINOUS COAL TYPES)*
(percentage, moist)

Federal region	ng SO_2/J (lb SO_2/MMBtu)		
	<464 (<1.08)	464-718 (1.08-1.67)	718-1,075 (1.67-2.50)
1. New England	--	--	--
2. New York/New Jersey	--	--	--
3. Middle Atlantic	--	--	--
4. South Atlantic	--	--	--
5. Midwest	6.9	6.9	6.9
6. Southwest	7.3	7.3	7.3
7. Central	6.0	6.0	6.0
8. North Central	8.4	6.9	6.9
9. West	7.3	7.3	7.3
10. Northwest	10.0	10.0	10.0

* Memorandum from K. Schweers and C. Ebert (ICF, Inc.) to J. Greenwald (EPA). Industrial Coal Prices for NSPS Analyses by Federal Regions. April 22, 1983.

TABLE A-4. AVERAGE HEAT CONTENT BY REGION
(BITUMINOUS COAL TYPES)*
J/g (MMBtu/short ton)

Federal region	ng SO_2/J (lb SO_2/MMBtu)					
	<464 (<1.08)	464-718 (1.08-1.67)	718-1,075 (1.67-2.50)	1,075-1,432 (2.50-3.33)	1,432-2,150 (3.33-5.00)	>2,150 (>5.00)
1. New England	29.66 (25.50)	29.66 (25.50)	29.77 (25.60)	30.59 (26.30)	29.89 (25.70)	28.78 (24.75)
2. New York/New Jersey	29.08 (25.00)	29.31 (25.20)	29.66 (25.50)	30.35 (26.10)	29.89 (25.70)	29.31 (25.20)
3. Middle Atlantic	29.41 (25.29)	29.54 (25.40)	29.56 (25.42)	29.47 (25.34)	29.08 (25.00)	28.91 (24.86)
4. South Atlantic	29.59 (25.44)	29.62 (25.47)	29.59 (25.44)	28.91 (24.86)	27.49 (23.64)	26.40 (22.70)
5. Midwest	29.13 (25.05)	29.20 (25.11)	27.44 (23.59)	26.71 (22.97)	26.67 (22.93)	27.12 (23.32)
6. Southwest	28.88 (24.83)	24.04 (20.67)	23.90 (20.55)	28.23 (24.27)	28.21 (24.26)	27.78 (23.89)
7. Central	27.75 (23.86)	28.30 (24.33)	27.98 (24.06)	26.62 (22.89)	26.54 (22.82)	26.75 (23.00)
8. North Central	25.24 (21.70)	24.03 (20.66)	23.92 (20.57)	-- --	-- --	-- --
9. West	24.43 (21.01)	23.49 (20.20)	22.85 (19.65)	-- --	-- --	-- --
10. Northwest	25.45 (21.88)	25.45 (21.88)	25.45 (21.88)	-- --	-- --	-- --

* Memorandum from K. Schweers and C. Ebert (ICF, Inc.) to J. Greenwald (EPA). Industrial Coal Prices for NSPS Analyses by Federal Regions. April 22, 1983.

TABLE A-5. AVERAGE HEAT CONTENT BY REGION
(SUBBITUMINOUS COAL TYPES)*
J/g (MMBtu/short ton)

Federal region	ng SO_2/J (lb SO_2/MMBtu)		
	<464 (<1.08)	464-718 (1.08-1.67)	718-1,075 (1.67-2.50)
1. New England	--	--	--
2. New York/New Jersey	--	--	--
3. Middle Atlantic	--	--	--
4. South Atlantic	--	--	--
5. Midwest	20.53 (17.65)	20.53 (17.65)	20.53 (17.65)
6. Southwest	19.93 (17.14)	19.93 (17.14)	19.93 (17.14)
7. Central	19.77 (17.00)	19.77 (17.00)	19.77 (17.00)
8. North Central	20.40 (17.54)	20.05 (17.24)	20.05 (17.24)
9. West	21.52 (18.50)	21.52 (18.50)	21.52 (18.50)
10. Northwest	22.10 (19.00)	22.10 (19.00)	22.10 (19.00)

* Memorandum from K. Schweers and C. Ebert (ICF, Inc.) to J. Greenwald (EPA). Industrial Coal Prices for NSPS Analyses by Federal Regions. April 22, 1983.